# Corrosion

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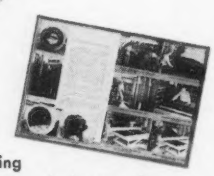
NATIONAL ASSOCIATION OF CORROSION ENGINEERS

VOL. 12 JANUARY, 1956 No. 1

# Locked-in lining prevents sewer disintegration



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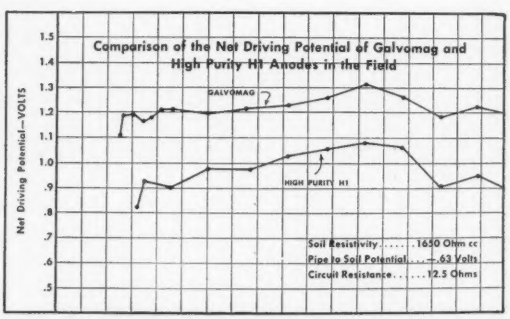


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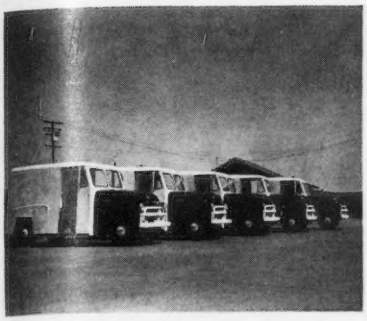

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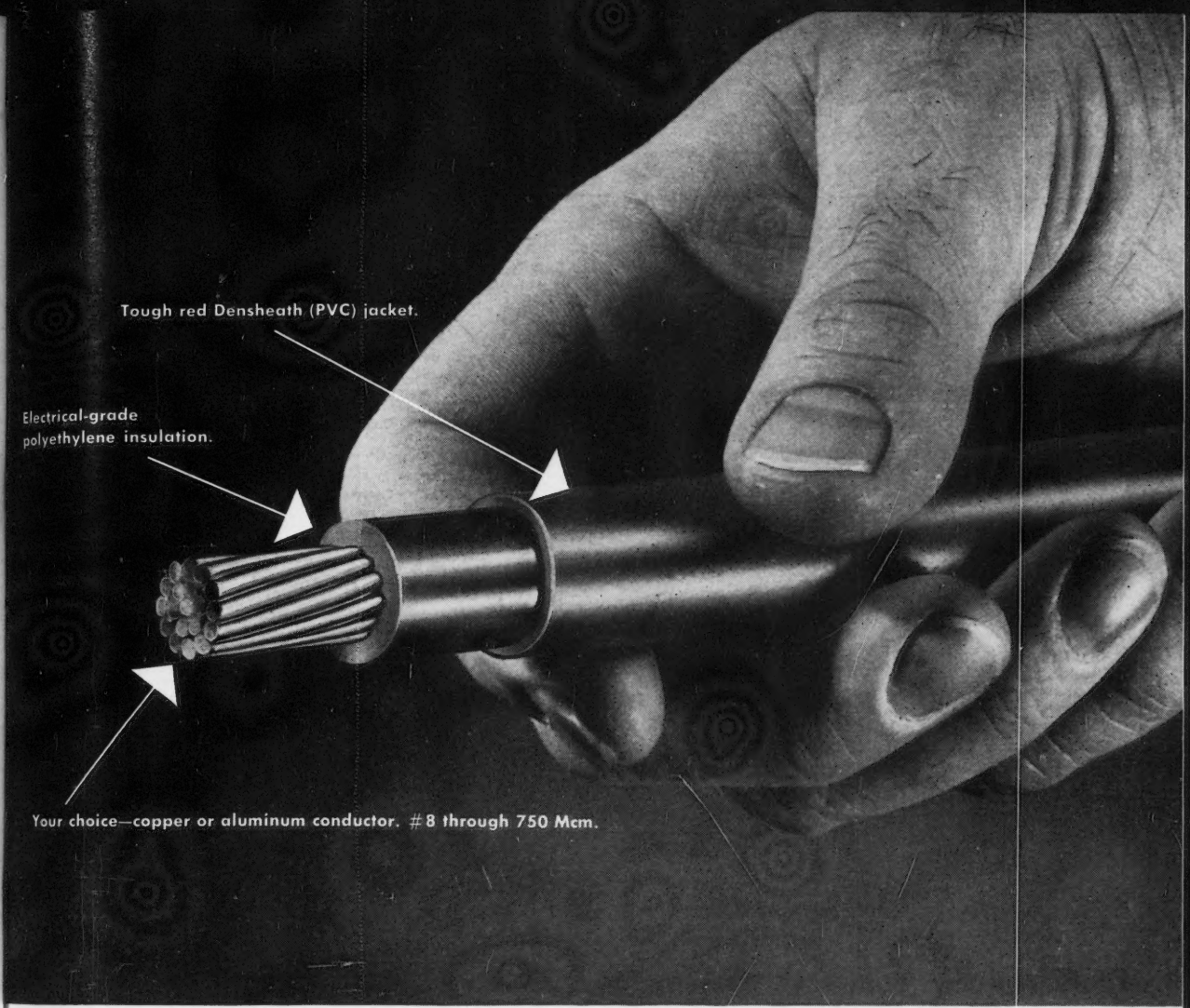
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J. S. McBride, Secretary; Owens-Corning Fiberglas Corp., 16 East 56th St., New York, N. Y.

#### • *T-5D-1 Questionnaires*

B. J. Philibert, Chairman, Mathieson Chemical Corp., Baltimore 3, Maryland

S. W. McIlrath, Vice Chairman, 151 E. 214 Street, Euclid 23, Ohio.

#### • *T-5D-2 Inorganic Acids*

Edward Layman, Chairman, Diamond Alkali Company, P. O. Box 686, Pasadena, Texas

R. L. Hughes, Vice Chairman, Spencer Chemical Co., 1231 Woodswether Rd., Kansas City, Missouri

J. F. Malone, Secretary, B. F. Goodrich Chemical Co., 2060 East Ninth Street, Cleveland 15, Ohio

#### • *T-5D-3 Inorganic Alkalies*

Peter Kimen, Chairman, Champion Paper & Fibre Co., Box 872, Pasadena, Texas

K. T. Snyder, Vice Chairman, 3730 Griggs Rd., Houston, Texas

L. B. Connelly, Secretary, Eastman Chemical Products Co., 1001 State National Building, Houston 2, Texas

#### • *T-5D-4 Gases*

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J. L. Forse, Vice Chairman, Dow Chemical Company, Plastics Technical Service, Midland, Michigan

William Eakins, Secretary, Chemical Corporation, Platank Division, West Warren, Massachusetts

#### • *T-5D-5 Water and Salt Solutions*

Paul Elliott, Chairman; Naugatuck Chemical Company, Kralastic Development, Naugatuck, Conn.

#### • *T-5D-6 Organic Chemicals*

R. E. Gackenbach, Chairman, American Cyanamid Company, Calco Chemical Division, Bound Brook, New Jersey

B. B. Pusey, Vice Chairman, Bakelite Co., Div. of U.C.C., Bound Brook, New Jersey

Wade Wolfe, Jr., Secretary, 73 Ermann Drive, Buffalo 17, New York

#### • *T-5D-7 Engineering Design*

O. H. Fenner, Chairman, Monsanto Chemical Company, 1700 South Second Street, St. Louis 4, Missouri

K. A. Phillips, Vice Chairman, American Zinc, Lead & Smelting Co., P. O. Box 495, East St. Louis, Illinois

W. B. Meyer, Secretary, St. Louis Metallizing Co., 625 South Sarah, St. Louis 10, Missouri

#### • *T-5D-8 Methods and Criteria for Evaluating Plastics in Chemical Environment*

R. F. Clarkson, Chairman, Mathieson Chemical Corp., P. O. Box 552, Pasadena, Texas

R. Lembcke, Secretary, Cities Service Res. & Dev. Co., 920 East Third, Tulsa 3, Oklahoma

## T-6 Protective Coatings

A. J. Liebman, Chairman, Pitmar Centrifugal Machine Corp., 4548 N. Charles St., Baltimore 10, Md.

L. L. Whiteneck, Vice Chairman, Long Beach Harbor Dept., 1333 El Embarcadero, Long Beach 2, California.

### T-6A Organic Coatings And Linings For Resistance To Chemical Corrosion

R. McFarland, Jr., Chairman, Hills-McCanna Co., 3025 N. W. Ave., Chicago 18, Illinois

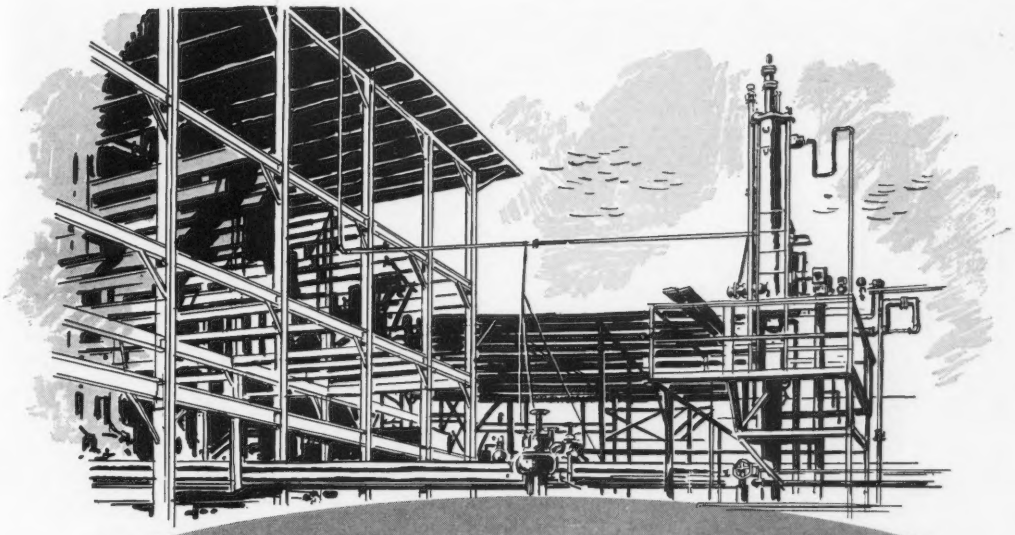
C. G. Munger, Vice Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.

L. A. Ferris, Secretary, E. I. DuPont de Nemours & Co., Inc., Polychemicals Dept., Wilmington, Delaware

#### • T-6A-1 Heavy Linings

H. C. Klein, Chairman, B. F. Goodrich Co., Cuyahoga Falls, Ohio

(Continued on Page 8)



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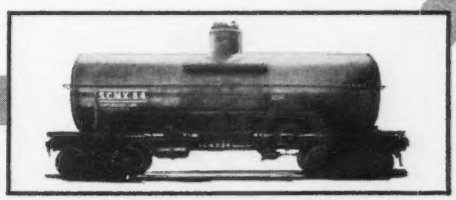

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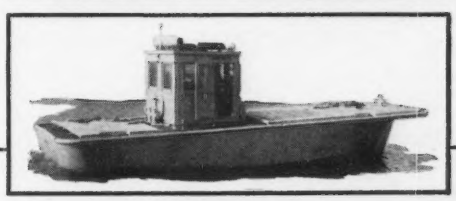

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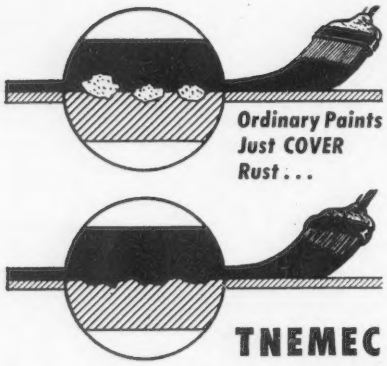


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(Continued from Page 6)

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R. L. Brown, Chairman, The Dow Chemical Co., Midland, Mich.

**• T-6A-4 Phenolics**

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**• T-6A-5 Polyethylene**

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**• T-6A-6 Rubber and Elastomers**

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**• T-6A-7 Silicones**

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**• T-6A-8 Methyacrylates**

L. S. Van Delinder, Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Va.

**• T-6A-9 Furanes**

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**• T-6A-10 Polyesters**

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**• T-6A-11 Epoxys**

C. G. Munger, Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.

**• T-6A-12 Fluorocarbons**

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**T-6B Protective Coatings for Resistance to Atmospheric Corrosion**

L. L. Sline, Chairman; Sline Industrial Painters, 2612 Gulf Terminal Drive, Houston, Texas.

Howard C. Dick, Vice Chairman, Products Research Service, Inc., Box 6116, New Orleans, Louisiana

**T-6C Protective Coatings for Resistance to Marine Corrosion**

Raymond P. Devoluy, Chairman, The Glidden Co., Room 1310, 52 Vanderbilt Avenue, New York 17, New York.

R. F. Daw, Vice-Chairman, The Texas Co., 135 East 42nd St., New York 17, N. Y.

**T-6E Protective Coatings in Petroleum Production**

J. L. Robertson, Chairman, Phillips Petroleum Co., Bartlesville, Oklahoma

**T-6G Surface Preparation For Organic Coatings**

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S. C. Frye, Vice Chairman, Research Dept., Bethlehem Steel Co., Bethlehem, Pa.

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George P. Gabriel, Vice-Chairman; Atlas Mineral Products Company, Mertztown, Pa.

**T-6R Protective Coatings Research**

Joseph Bigos, Chairman, Steel Structures Painting Council, Mellon Inst., 4400 Fifth Ave. Pittsburgh 13, Pa.

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J. M. Fouts, Chairman; New York Telephone Co., 63 Delavan Ave., Buffalo 8, New York

E. H. Caldwell, Vice-Chairman; Oldbury Electrochemical Co., 5001 Buffalo Ave., Niagara Falls, New York

Walter A. Szymanski, Secretary-Treasurer; Hooker Electrochemical Co., P. O. Box 344, Niagara Falls, New York

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J. A. Caldwell, Ass't Secretary-Treasurer; Humble Oil & Refining Co., Box 2180, Houston, Texas

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William R. Barber, Jr., Secretary-Treasurer; Electric Steel Foundry, 2141 N.W. 25th Ave., Portland, Oregon

**Directories of Regional and Section Officers and Technical Committees are run on alternate months. Next insertion of the complete directory of regional and sectional officers will be in the February issue.**

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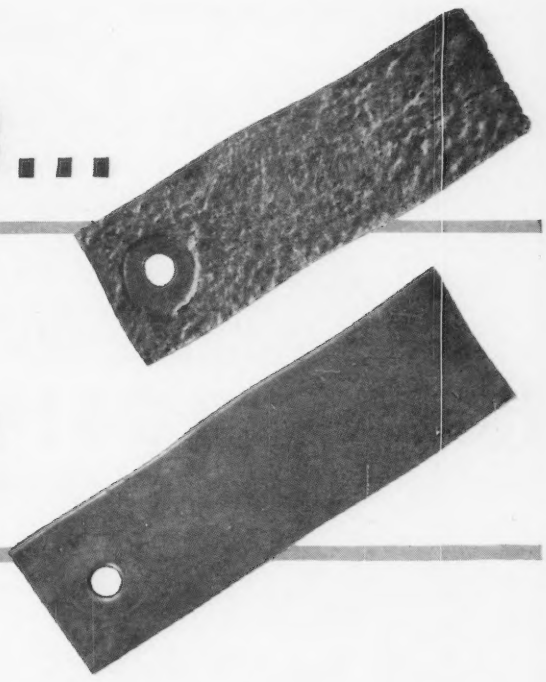

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E. C. Greco, Vice Chairman; United Gas Corp., Box 1407, Shreveport, La.

W. F. Fair, Jr., Vice President NACE; Koppers Co., Inc., Tar Products Div., Technical Section, 15, Plum St., Verona, Pennsylvania.

Chairmen of T-1 through T-6 also are members of this committee.

## T-1 Corrosion in Oil and Gas Well Equipment

W. F. Oxford, Jr., Chairman, Sun Oil Co., Box 2831, Beaumont, Texas.

Jack L. Battle, Vice Chairman, Humble Oil & Refining Co., Box 2180, Houston, Texas

### T-1A Corrosion in Oil and Gas Well Equipment, Los Angeles Area

F. W. Schremp, Chairman, California Research Corp., Box 446, La Habra, Calif.

Howard Lorenz, Vice Chairman, Standard Oil Co., 11-C Camp, Taft, Califonia.

### T-1B Condensate Well Corrosion

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W. H. Edwards, Vice Chairman, Superior Oil Company, 400 Oil and Gas Building, Houston, Texas

### T-1C Sweet Oil Well Corrosion

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H. E. Waldrip, Vice Chairman, Gulf Oil Corp., 5311 Kirby Dr., Houston, Texas.

### T-1D Sour Oil Well Corrosion

J. A. Caldwell, Chairman, Humble Oil & Refining Co., Box 2180, Houston, Texas

R. L. Elkins, Vice Chairman, Shell Oil Corp., Box 1509, Midland, Texas

W. C. Koger, Vice Chairman, Cities Service Oil Company, Cities Service Building, Bartlesville, Okla.

### • *T-1D-1 Fundamentals of Corrosion*

J. D. Sudbury, Chairman, Production Research Division, Development and Research Dept., Continental Oil Company, Ponca City, Oklahoma

### T-1F Metallurgy

F. J. Radd, Chairman, Continental Oil Co., Research & Development Lab., Ponca City, Oklahoma

F. L. Current, Vice Chairman, Oil Well Supply Co., Oil City, Pennsylvania

### T-1G Sulfide Stress Corrosion Cracking

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L. W. Vollmer, Vice Chairman, Gulf Research & Development Corp., Drawer 2038, Pittsburgh, Pa.

### T-1H Oil String Casing Corrosion

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R. L. Elkins, Vice Chairman, Shell Oil Corp., Box 1509, Midland, Texas.

W. C. Koger, Vice Chairman, Cities Service Oil Company, Cities Service Building, Bartlesville, Okla.

### • *T-1H-1 Oil String Casing Corrosion, West Texas, New Mexico Area*

R. L. Elkins, Chairman, Shell Oil Corp., Box 1509, Midland, Texas.

### • *T-1H-2 Oil String Casing Corrosion, West Kansas Area*

W. C. Koger, Chairman, Cities Service Oil Company, Cities Service Building, Bartlesville Oklahoma.

### T-1J Oil Field Structural Plastics

B. W. Bradley, Chairman; Shell Oil Co., 50 West 50th St., New York, N. Y.

### T-1K Inhibitors For Oil And Gas Wells

J. C. Spalding, Jr., Chairman, Sun Oil Co., Box 2880, Dallas, Texas

E. C. Greco, Vice Chairman, United Gas Corp., Box 1407, Shreveport, Louisiana

### T-1M Corrosion of Oil and Gas Well Producing Equipment in Offshore Installations

D. F. Dial, Jr., Chairman, Pure Oil Co., Box 239, Houston, Texas.

F. E. Blount, Vice Chairman, Magnolia Petroleum Co., Box 900, Dallas, Texas

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W. H. Stewart, Chairman, Sun Pipe Line Co., Sun Oil Co., San Jacinto Bldg., Beaumont, Texas.

L. P. Sudrabin, Vice Chairman, Electro Rust-Proofing Corp., Box 178, Newark, New Jersey

### T-2A Galvanic Anodes

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### T-2B Anodes For Impressed Currents

T. J. Maitland, Chairman, American Tel. & Tel. Co., 32 Sixth Ave., New York 13, New York.

### T-2C Minimum Current Requirements

L. P. Sudrabin, Chairman, Electro Rust-Proofing Corp., Box 178, Newark, New Jersey.

R. M. Wainwright, Vice Chairman, University of Illinois, Department of Electrical Engineering, Urbana.

### • *T-2C-1 Criteria for Cathodic Protection*

Francis W. Ringer, Chairman, 7 Hampden Ave., Narberth, Pennsylvania.

### T-2D Standardization of Procedures For Measuring Pipe Coating Leakage Conductance

W. E. Huddleston, Chairman, Huddleston Engineering Co., Box 998, Bartlesville, Okla.

L. F. Heverly, Vice Chairman, 2210 W. High St., Lima, Ohio

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A. W. Jasek, Vice Chairman, Humble Pipe Line Co., Drawer 2220, Houston, Texas

### T-2F Internal Corrosion of Crude Oil Pipe Lines and Tanks

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R. L. Elkins, Vice Chairman, Shell Oil Co., Box 1509, Midland, Texas

### T-2G Coal Tar Coatings for Underground Use

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W. F. Fair, Jr., Vice Chairman, Koppers Co., Inc., Tar Products Div., Tech. Serv., 15 Plum St., Verona, Pa.

### T-2H Asphalt Type Pipe Coatings

R. J. Schmidt, Chairman; California Research Corp., 576 Standard Avenue, Richmond, Cal.

P. E. Reynolds, Vice Chairman, Pacific Gas & Electric Co., 245 Market St., San Francisco, California.

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### T-3A Corrosion Inhibitors

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D. A. Vaughan, Vice Chairman, Battelle Memorial Institute, 505 King Avenue, Columbus, Ohio

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G. M. Magee, Vice Chairman, Assoc. Amer. Railroads, Technology Center, Chicago 16, Illinois

### • *T-3E-1 Corrosion of Railroad Tank Cars*

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L. R. Honnaker, Vice Chairman, Engineering Materials Group, Engineering Dept., E. I. DuPont de Nemours & Co., Inc., Wilmington, Delaware.

### • *T-3E-2 Corrosion in Railroad Hopper Cars*

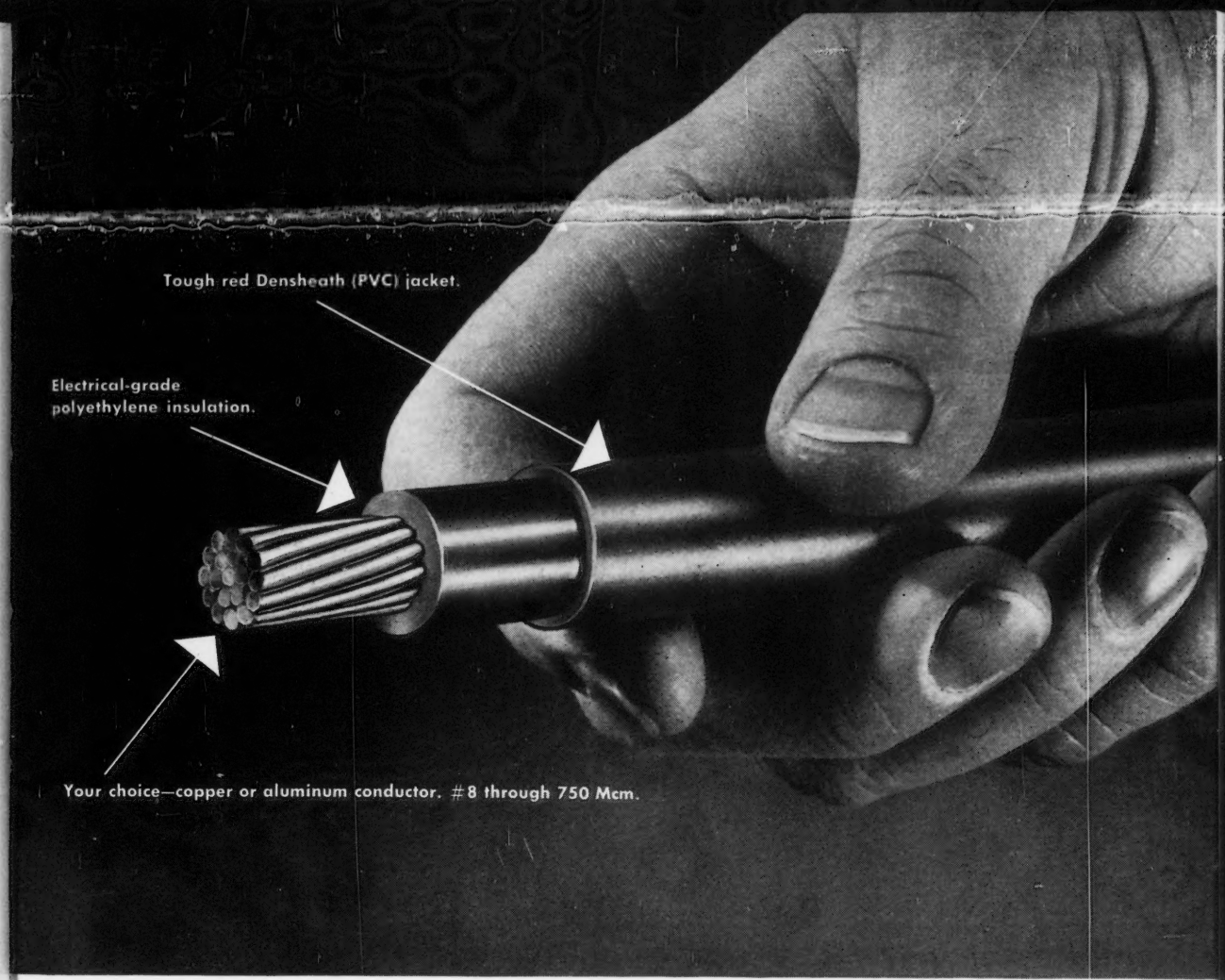
Robert Byrne, Chairman, Assoc. Amer. Railroads, 3140 South Federal Street, Chicago 16, Illinois

### T-3F Corrosion by High Purity Water

D. J. Depaul, Chairman, Westinghouse Electric Corp., Box 1526, Pittsburgh 30, Pa.

J. F. Eckel, Vice Chairman, General Electric Co., KAPL, Schenectady, New York

(Continued on Page 6)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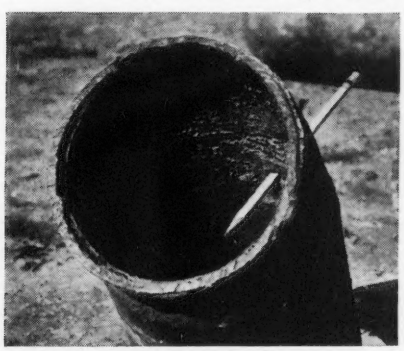

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### T-3H Tanker Corrosion

W. S. Quimby, Temporary Chairman, The Texas Co., 135 East 42nd St., New York, N. Y.

## T-4 UTILITIES

F. E. Kulman, Chairman, Consolidated Edison Co. of N. Y., Inc., 4 Irving Place, New York 3, N. Y.

Irwin C. Dietze, Vice Chairman, Dept. of Water & Power, Box 3669, Terminal Annex, Los Angeles, Calif.

### T-4A Effects of Electrical Grounding on Corrosion

Ray M. Wainwright, Chairman; University of Illionis, Department of Electrical Engineering, Urbana.

### T-4B Corrosion of Cable Sheaths

Irwin C. Dietze, Chairman, Dept. of Water & Power, Box 3669, Terminal Annex, Los Angeles, California

D. T. Rosselle, Vice Chairman, Southern Bell Tel. & Tel. Co., 1432 Hurt Bldg., Atlanta, Ga.

#### • T-4B-1 Lead and Other Metallic Sheaths

T. J. Maitland, Chairman, American Tel. & Tel. Co., 32 Sixth Ave., New York 13, New York

#### • T-4B-2 Cathodic Protection

R. M. Lawall, Chairman, Amer. Tel. & Tel. Co., 1538 Union Commerce Bldg., Cleveland 14, Ohio

J. J. Pokorny, Vice Chairman, Cleveland Elec. Illuminating Co., 75 Public Sq., Cleveland 1, Ohio

#### • T-4B-3 Tests and Surveys

J. C. Howell, Chairman, Public Service Electric & Gas Co., 200 Boyden Ave., Maplewood, New Jersey

D. R. Werner, Vice Chairman, American Tel. & Tel. Co., 324 East 11th St., Kansas City, Missouri.

#### • T-4B-4 Protection of Pipe Type Cables

H. W. Dieck, Chairman, Long Island Lighting Co., 250 Old Country Road, Mineola, Long Island, N. Y.

J. B. Prime, Jr., Vice-Chairman, Florida Power & Light Co., Box 3100, Miami, Florida

#### • T-4B-5 Non-Metallic Sheaths and Coatings

G. H. Hunt, Chairman, Simplex Wire & Cable Co., 79 Sidney St., Cambridge 39, Massachusetts

#### • T-4B-6 Stray Current Electrolysis

J. Svetlik, Chairman, Northern Indiana Public Service Co., 5265 Hohman Ave., Hammond, Indiana

G. H. Cantwell, Vice Chairman, Indiana Bell Telephone Co., 240 N. Meridian St., Indianapolis, Indiana.

### T-4D Corrosion By Deicing Salts

M. B. Hart, Chairman, Illinois Bell Telephone Co., 208 West Washington St., Chicago 6, Illinois

J. A. Temmerman, Vice Chairman; City of Rochester, 242 Main Street W., Rochester, New York

### T-4E Corrosion by Domestic Waters

T. E. Larson, Chairman, Illinois State Water Survey, Box 232, Urbana, Illinois.

### T-4F Materials Selection for Corrosion Mitigation in the Utility Industry

New chairman to be elected.

#### • T-4F-1 Water Meter Corrosion

New chairman to be appointed.

## T-5 Corrosion Problems in the Process Industries

Wm. G. Ashbaugh, Chairman, Carbide & Carbon Chemicals Co., Texas City, Texas.

R. I. Zimmerer, Vice-Chairman, Westvaco Chemical Division, Food Machinery & Chemical Corp., Drawer 8127, S. Charleston, West Virginia

### T-5A Chemical Manufacturing Industry

R. I. Zimmerer, Chairman, Westvaco Chlor-Alkali Div., Food Machinery & Chemical Corp., Drawer 8127, Charleston 3, West Virginia

A. C. Hamstead, Vice-Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Virginia.

#### • T-5A-1 Sulfuric Acid

C. L. Bulow, Chairman, Bridgeport Brass Co., 30 Grand St., Bridgeport, Conn.

W. A. Luce, Vice Chairman, The Duriron Co., Box 1019, Dayton, Ohio

#### • T-5A-3 Acetic Acid

H. O. Teeple, Chairman, The International Nickel Co., Inc., 67 Wall St., New York, New York

#### • T-5A-4 Chlorine

Wayne Inbody, Chairman, Diamond Alkali Co., Box 348, Painesville, Ohio

#### • T-5A-5 Nitric Acid

J. L. English, Chairman, Oak Ridge National Laboratory, Box P, Oak Ridge, Tenn.

W. H. Burton, Vice-Chairman, General Chemical Division, Allied Chemical & Dye Corp., Camden, New Jersey

#### • T-5A-6 HF Corrosion

T. L. Hoffman, Chairman, Phillips Petroleum Co., Atomic Energy Div., Box 1259, Idaho Falls, Idaho.

### T-5B High Temperature Corrosion

John Halbig, Chairman, Armco Steel Corp., Middletown, Ohio.

E. N. Skinner, Vice-Chairman, The International Nickel Co., Inc., 67 Wall St., New York, N. Y.

#### • T-5B-2 Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry

M. E. Holmberg, Chairman, 4101 San Jacinto St., Houston, Texas.

#### • T-5B-3 Oil Ash Corrosion

(Chairman to be appointed)

#### • T-5B-4 High Temperature Halogenation

(Chairman to be appointed)

#### • T-5B-5 Corrosion by Molten Salts and Metals

(Chairman to be appointed)

### T-5C Corrosion by Cooling Waters

#### • T-5C-1 Corrosion by Cooling Waters (South Central Region)

A. S. Krisher, Chairman, Monsanto Chemical Co., Texas City, Texas

C. P. Dillon, Vice-Chairman, Carbide & Carbon Chemicals Co., Texas City, Texas

J. L. Weiss, Secretary, Diamond Alkali Co., Pasadena, Texas

### T-5D Plastic Materials of Construction

S. W. McIlrath, Chairman; 151 East 214th St., Euclid, Ohio

J. S. McBride, Secretary; Owens-Corning Fiberglas Corp., 16 East 56th St., New York, N. Y.

#### • T-5D-1 Questionnaires

B. J. Philibert, Chairman, Mathieson Chemical Corp., Baltimore 3, Maryland

S. W. McIlrath, Vice Chairman, 151 E. 214 Street, Euclid 23, Ohio.

#### • T-5D-2 Inorganic Acids

Edward Layman, Chairman, Diamond Alkali Company, P. O. Box 686, Pasadena, Texas

R. L. Hughes, Vice Chairman, Spencer Chemical Co., 1231 Woodswether Rd., Kansas City, Missouri

J. F. Malone, Secretary, B. F. Goodrich Chemical Co., 2060 East Ninth Street, Cleveland 15, Ohio

#### • T-5D-3 Inorganic Alkalies

Peter Kimen, Chairman, Champion Paper & Fibre Co., Box 872, Pasadena, Texas

K. T. Snyder, Vice Chairman, 3730 Griggs Rd., Houston, Texas

L. B. Connelly, Secretary, Eastman Chemical Products Co., 1001 State National Building, Houston 2, Texas

#### • T-5D-4 Gases

Beaumont Thomas, Chairman, Stebbins Eng. & Mfg. Co., Eastern Blvd., Watertown, New York

J. L. Forse, Vice Chairman, Dow Chemical Company, Plastics Technical Service, Midland, Michigan

William Eakins, Secretary, Chemical Corporation, Platank Division, West Warren, Massachusetts

#### • T-5D-5 Water and Salt Solutions

Paul Elliott, Chairman; Naugatuck Chemical Company, Kralastic Development, Naugatuck, Conn.

#### • T-5D-6 Organic Chemicals

R. E. Gackenbach, Chairman, American Cyanamid Company, Calco Chemical Division, Bound Brook, New Jersey

B. B. Pusey, Vice Chairman, Bakelite Co., Div. of U.C.C., Bound Brook, New Jersey

Wade Wolfe, Jr., Secretary, 73 Ermann Drive, Buffalo 17, New York

#### • T-5D-7 Engineering Design

O. H. Fenner, Chairman, Monsanto Chemical Company, 1700 South Second Street, St. Louis 4, Missouri

K. A. Phillips, Vice Chairman, American Zinc, Lead & Smelting Co., P. O. Box 495, East St. Louis, Illinois

W. B. Meyer, Secretary, St. Louis Metallizing Co., 625 South Sarah, St. Louis 10, Missouri

#### • T-5D-8 Methods and Criteria for Evaluating Plastics in Chemical Environment

R. F. Clarkson, Chairman, Mathieson Chemical Corp., P. O. Box 552, Pasadena, Texas

R. Lembcke, Secretary, Cities Service Res. & Dev. Co., 920 East Third, Tulsa 3, Oklahoma

## T-6 Protective Coatings

A. J. Liebman, Chairman, Pitmar Centrifugal Machine Corp., 4548 N. Charles St., Baltimore 10, Md.

L. L. Whiteneck, Vice Chairman, Long Beach Harbor Dept., 1333 El Embarcadero, Long Beach 2, California.

### T-6A Organic Coatings And Linings For Resistance To Chemical Corrosion

R. McFarland, Jr., Chairman, Hills-McCanna Co., 3025 N. W. Ave., Chicago 18, Illinois

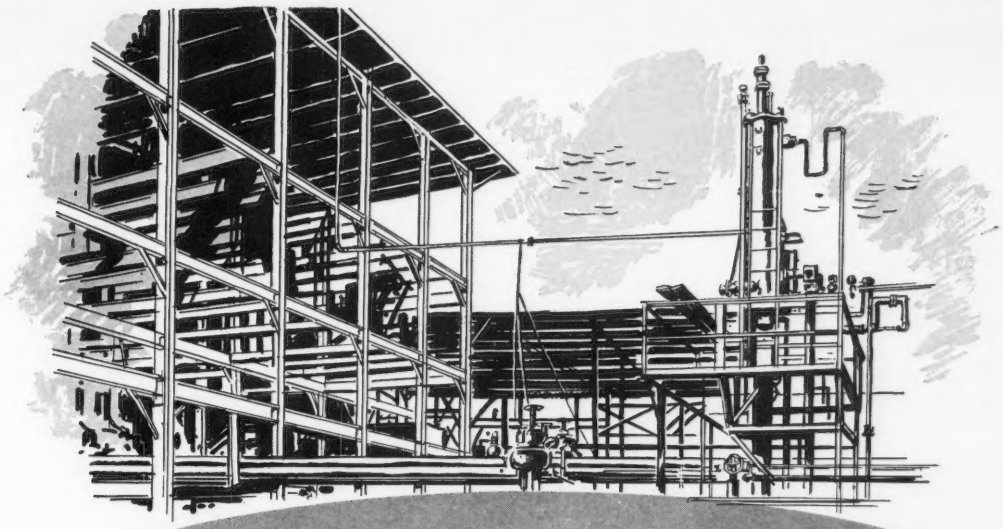
C. G. Munger, Vice Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.

L. A. Ferris, Secretary, E. I. DuPont de Nemours & Co., Inc., Polychemicals Dept., Wilmington, Delaware

#### • T-6A-1 Heavy Linings

H. C. Klein, Chairman, B. F. Goodrich Co., Cuyahoga Falls, Ohio

(Continued on Page 8)



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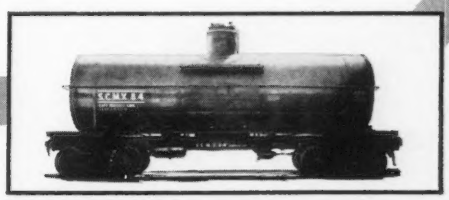
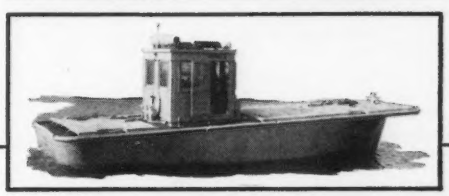


This tank car is Copon-coated both inside and out to protect it from the ravages of rust and corrosion.



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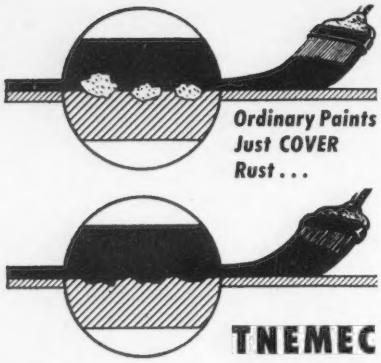


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# Directory of Technical Committees

(Continued from Page 6)

**• T-6-2 Vinyl Coatings**

K. Tator, Chairman, 2020 Montour Street, Coraopolis, Pa.

**• T-6A-3 Vinylidene Chloride Polymers**

R. L. Brown, Chairman, The Dow Chemical Co., Midland, Mich.

**• T-6A-4 Phenolics**

F. Baskett, Chairman, 4334 Ella Blvd., Houston, Texas

**• T-6A-5 Polyethylene**

L. S. Van Delinder, Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Va.

**• T-6A-6 Rubber and Elastomers**

H. C. Klein, Chairman, B. F. Goodrich Co., Cuyahoga Falls, Ohio

**• T-6A-7 Silicones**

R. McFarland, Jr., Chairman, Hills-McCanna Co., 3025 N. Western Ave., Chicago, Ill.

**• T-6A-8 Methyacrylates**

L. S. Van Delinder, Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Va.

**• T-6A-9 Furanes**

F. Baskett, Chairman, 4334 Ella Blvd., Houston, Texas

**• T-6A-10 Polyesters**

R. R. Pierce, Chairman, Pennsylvania Salt Mfg. Co., 3 Penn Center Plaza, Philadelphia, Pa.

**• T-6A-11 Epoxys**

C. G. Munger, Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.

**• T-6A-12 Fluorocarbons**

L. A. Ferris, Chairman, E. I. DuPont DeNemours & Co., Inc., Wilmington, Delaware

**T-6B Protective Coatings for Resistance to Atmospheric Corrosion**

L. L. Sline, Chairman; Sline Industrial Painters, 2612 Gulf Terminal Drive, Houston, Texas.

Howard C. Dick, Vice Chairman, Products Research Service, Inc., Box 6116, New Orleans, Louisiana

**T-6C Protective Coatings for Resistance to Marine Corrosion**

Raymond P. Devoluy, Chairman, The Glidden Co., Room 1310, 52 Vanderbilt Avenue, New York 17, New York.

R. F. Daw, Vice-Chairman, The Texas Co., 135 East 42nd St., New York 17, N. Y.

**T-6E Protective Coatings in Petroleum Production**

J. L. Robertson, Chairman, Phillips Petroleum Co., Bartlesville, Oklahoma

**T-6G Surface Preparation For Organic Coatings**

S. E. Jack, Chairman, Aluminium Laboratories, Ltd., Box 84, Kingston, Ontario, Canada

S. C. Frye, Vice Chairman, Research Dept., Bethlehem Steel Co., Bethlehem, Pa.

**T-6H Glass Linings And Vitreous Enamels**

G. H. McIntyre, Chairman, Ferro-Enamel Corp., Harvard & 56th Street, Cleveland 5, Ohio

**T-6K Corrosion Resistant Construction With Masonry And Allied Materials**

L. R. Honnaker, Chairman; E. I. du Pont deNemours & Co., Inc., Engineering Department, Louviers Building, Newark, Del.

George P. Gabriel, Vice-Chairman; Atlas Mineral Products Company, Mertztown, Pa.

**T-6R Protective Coatings Research**

Joseph Bigos, Chairman, Steel Structures Painting Council, Mellon Inst., 4400 Fifth Ave. Pittsburgh 13, Pa.

# Regional and Sectional Officers—Changes

**• Niagara Frontier Section**

J. M. Fouts, Chairman; New York Telephone Co., 63 Delavan Ave., Buffalo 8, New York

E. H. Caldwell, Vice-Chairman; Oldbury Electrochemical Co., 5001 Buffalo Ave., Niagara Falls, New York

Walter A. Szymanski, Secretary-Treasurer; Hooker Electrochemical Co., P. O. Box 344, Niagara Falls, New York

**• Greater St. Louis Section**

A. W. Thiele, Treasurer; Mallinckrodt Chemical Works, 3600 North Second Street, St. Louis, Missouri

**SOUTHEAST REGION**

E. P. Tait, Director; Alloy Steel Products Co., 76 4th St., N.W., Atlanta, Georgia

Fred D. Stull, Chairman; Texas Gas Transmission Corp., 401 W. 3rd St., Owensboro, Kentucky

Arthur B. Smith, Vice Chairman; Amercoat Corp., Jacksonville, Florida

R. C. Martin, Secretary-Treasurer; Plantation Pipe Line Co., Atlanta, Georgia

**SOUTH CENTRAL REGION**

H. E. Waldrip, Director; Gulf Oil Corp., Drawer 2100, Houston, Texas

John W. Nee, Chairman; Briner Paint Mfg. Co., 3713 Agnes St., Corpus Christi, Texas

Jack P. Barrett, Vice Chairman; Stanolind Oil & Gas Co., Box 591, Tulsa, Oklahoma

J. C. Spalding, Jr., Secretary-Treasurer; Sun Oil Co., Box 2880, Dallas, Texas

J. A. Caldwell, Ass't Secretary-Treasurer; Humble Oil & Refining Co., Box 2180, Houston, Texas

**• North Texas Section**

Edwin H. Muehlhause, Chairman; Lone Star Gas Co., 301 S. Harwood, Dallas, Texas

Monte Kaplan, Vice-Chairman; Atlantic Refining Co., Box 2819, Dallas, Texas

Richard B. Bender, Secretary-Treasurer; Plastic Engr. & Sales Corp., Box 1037, Fort Worth, Texas

**• Portland Section**

Norman H. Burnett, Chairman; Huntington Rubber Mills, 1326 N.E. 71 Ave., Portland, Oregon

R. S. Baynham, Vice-Chairman; Dearborn Chemical Co., 7434 S.E. 36 Ave., Portland 2, Oregon

William R. Barber, Jr., Secretary-Treasurer; Electric Steel Foundry, 2141 N.W. 25th Ave., Portland, Oregon

**Directories of Regional and Section Officers and Technical Committees are run on alternate months. Next insertion of the complete directory of regional and sectional officers will be in the February issue.**

# EVEN THE TOUGHEST ACIDS Shun this Joint

In acid-proof brick floors — in any type of corrosion-resistant masonry — the joint between the bricks is the critical point. Ordinary mortar joints won't do. Even many specialized "acid-proof" cements will handle only a limited range of acids. Others will handle acids but fail quickly under alkali attack.

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*The U. S. Stoneware Co. has prepared two booklets which will prove helpful to any company concerned with any type of corrosion-resistant masonry.* **"HOW TO BUILD AN ACID-PROOF BRICK FLOOR"** *and* **"CORROSION-RESISTANT MASONRY CONSTRUCTION GUIDE"** *are down-to-earth books with a wealth of pertinent, practical information. They are free, by request on your company letterhead. Write: The U. S. Stoneware Co., Dept. CO 156, Akron 9, Ohio.*

375-D

PUBLICATION DATE
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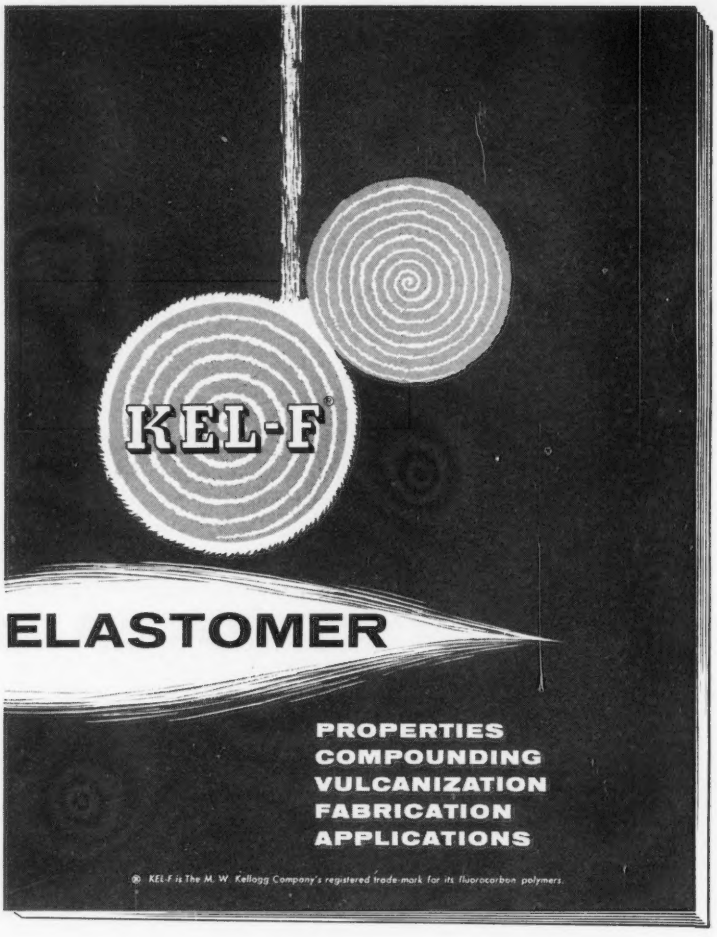


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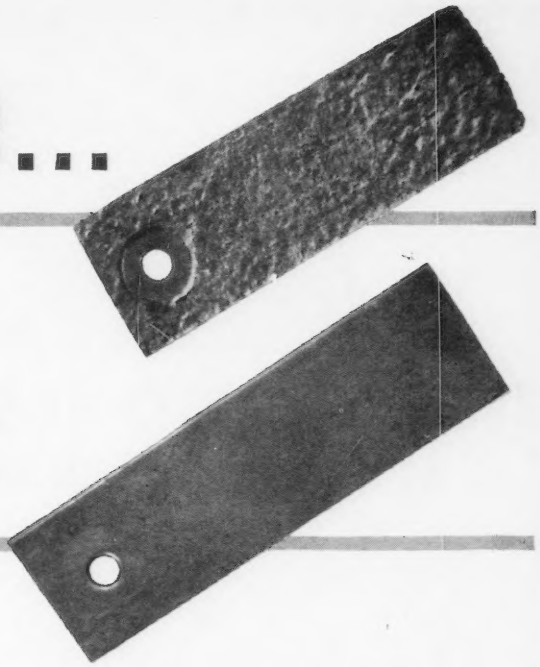
# before...



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** These wells receiving "anti-corrosion" treatment. Replaced by Visco.*

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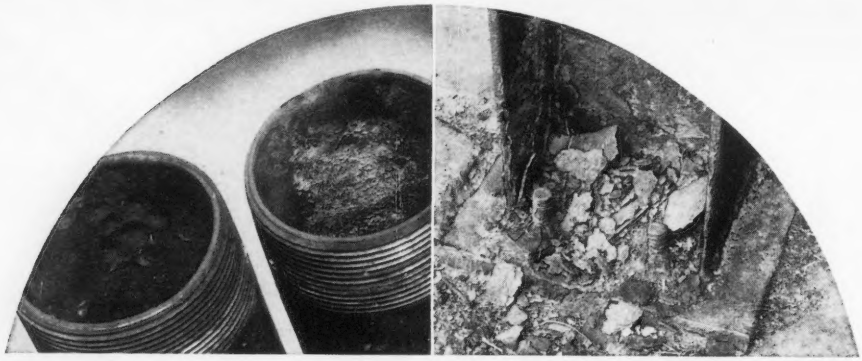
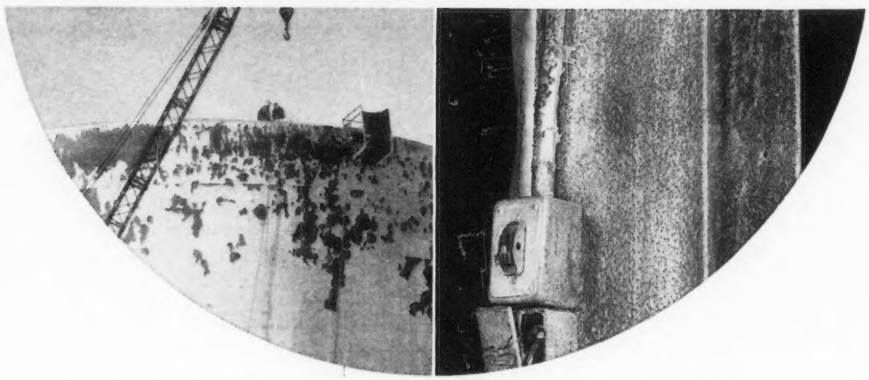


# IN CORROSION RESISTANCE
## it's just one thing after another . . .



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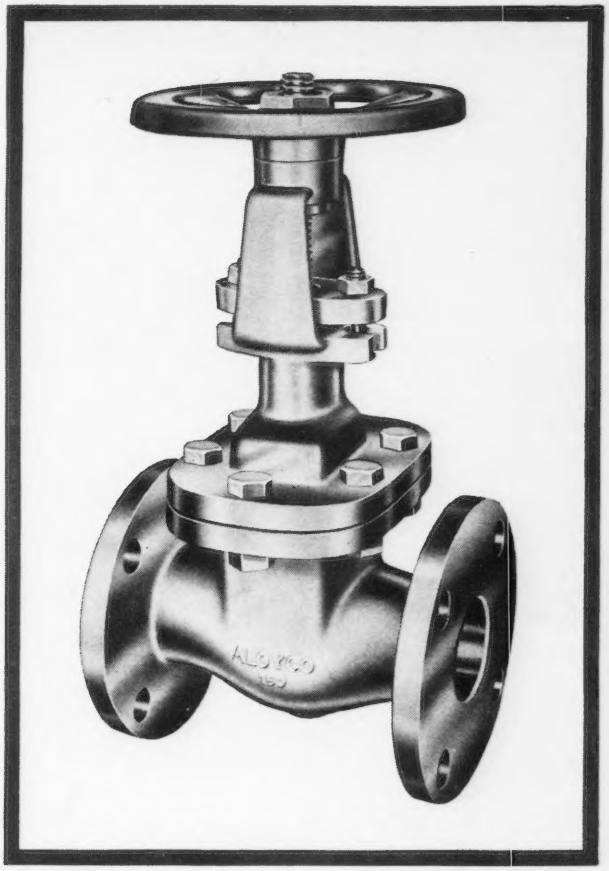
**Cook's laboratory and field experience and continuing research**
*with every type of corrosion resisting substance insures you the right inhibitor for your own case. We'll be happy to work with you. Write about your problem today.*

# Are your valves over their heads in corrosive reducing solutions?

## Switch to Aloyco Monel or Nickel Valves!



**ALOYCO MONEL VALVES** are used extensively in handling alkalies, salt waters, food products, organic substances, and many air-free acids.

Keeping corrosive solutions of mineral and organic acids, alkalies and salts under control is a job for Aloyco Monel or Nickel valves.

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Both alloys are available in a wide range of Aloyco valve designs. They're cast by induction melting at Aloyco foundries and machined in Aloyco plants. New bulletin #9, couponed below, provides complete information. Write today to ALLOY STEEL PRODUCTS CO., INC., Linden, N. J.

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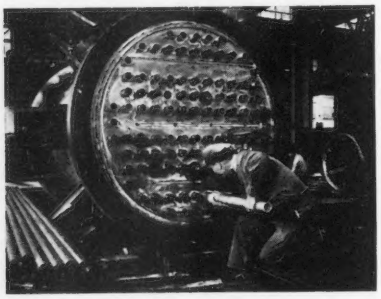
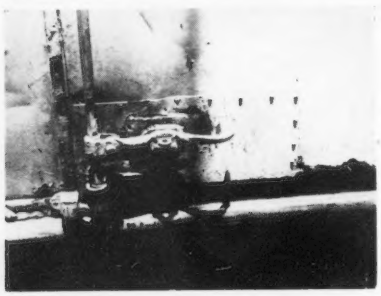
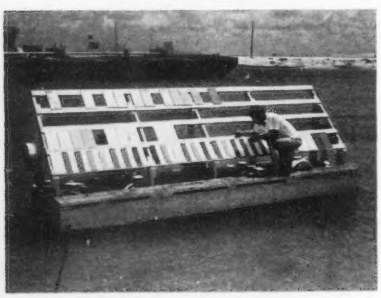


Control by Material Selection



Control by Correct Design



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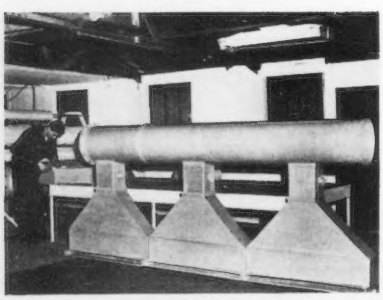

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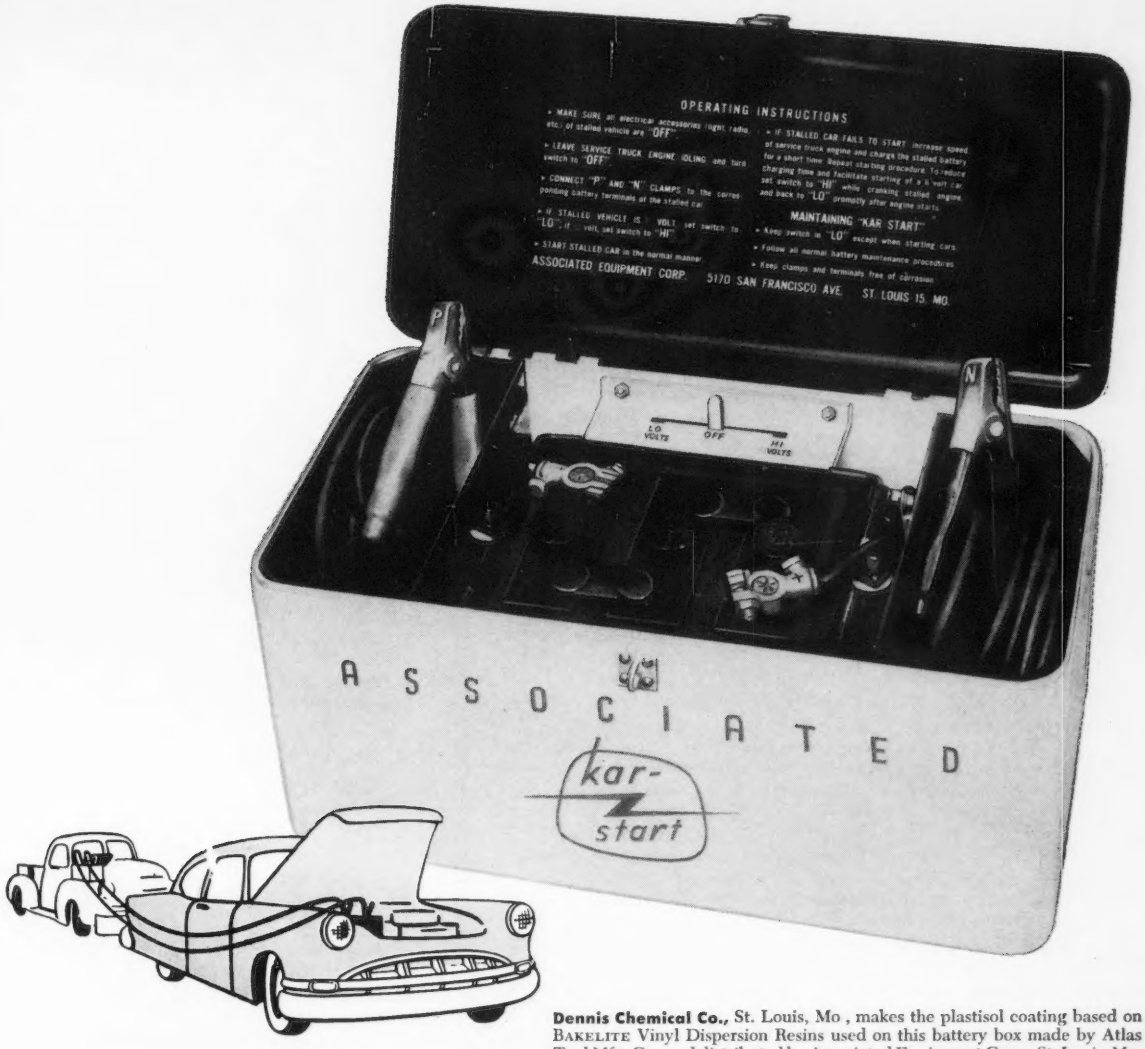


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# Induced Alternating Current Used for Cathodic Protection of a Coated Pipe Line*

By S. J. BELLASSAI*

## Abstract

After making repairs on a leak on a coated line through a salt marsh and paralleling a high voltage high line, it was learned that although considerable gradients existed in the earth adjacent to the high line there was no correlation in the measured quantities. It had been considered that natural rectification of the induced AC voltage was occurring. After tests with coupons buried near the pipe line showed the pipeline was predominantly positive to earth at the leak location, a test ground bed was constructed to examine the feasibility of rectifying the induced alternating current. Measurement of the rectified voltage between the pipeline and the test ground bed through a 25-ampere, 18-volt selenium rectifier was 5 volts DC available for cathodic protection. A 5-ampere, 15-volt selenium stack, ten 3-inch x 60-inch graphite rods and 500 feet of 1/0 copper cable was calculated to provide circuit resistance of the required value to protect the line cathodically.

## Introduction

THE SEWAREN lateral of Transcontinental Gas Pipe Line Corporation consists of 1.1 miles of 6.625-inch O.D. x 0.375-inch W.T. somastic coated welded steel pipe. The lateral is insulated at the point of take-off from the 30-inch main transmission line and from customers' facilities at the company's measuring and regulating station.

The right of way parallels for practically its entire length a three and four tower high-voltage group of power transmission lines leaving from the Public Service Electric & Gas Company of New Jersey, Sewaren Generating Station.

The first 3,700 feet of the lateral in paralleling the tower lines lies in sandy loam soil. It then crosses Smith Creek, a tidal river and enters a wet salt marsh, which it traverses an additional 1800 feet prior to terminating at the measuring and regulating station.

On April 16, 1954, almost four years after the construction of the line, a corrosion leak occurred at a point approximately in the center of the section in the salt marsh. Repairs were difficult to make because of the fact that the entire marsh inundated during high tide periods; the situation was complicated further when it was discovered that even during low tide stages the immediate work area was relatively inaccessible. The repair finally was completed successfully by blowing the line down and welding a half-sole patch approximately 30 inches long over the corrosion-damaged section.

The leak occurred on the pipe at approximately the 5 o'clock location. The somastic coating appeared to be in good condition except for a small area near the leak which had been blown away by escaping gases. The soil resistivity at this location in the marsh was found to be 76 ohm-centimeters.

Electrical measurements made at the leak location with a steel bar reference electrode showed that the pipe/soil voltage varied from —0.6 to +0.1 volt; for the measurements the negative terminal of the voltmeter was connected to the pipe line. When the same measurement was made with a copper sulfate electrode a variation from —0.1 to +0.6 volt was shown.

## Induced Alternating Current

The excessive vibration of the needle occurring while these measurements were being taken was an indication that an appreciable magnitude of alternating current was being induced on the pipe line. This raised the question as to whether or not soil conditions were such that the induced alternating current was being rectified with a resulting aggravation of corrosion conditions.

In order that the induced alternating current could be studied, an oscilloscope and a portable 110 volt, 60 cycle, AC generator were used to measure the amount of induced alternating current voltage between pipe line and earth. The oscilloscope measurement verified previous measurements made with a Model 240 Simpson meter which had shown that the magnitude of AC voltage between pipe line and earth was at a steady magnitude of 8.5 volts when a steel bar was used as a reference. The oscilloscope showed that this induced AC voltage had a perfect sine wave.

Various additional measurements were made in

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order to determine if rectification of the alternating current were occurring. These measurements consisted of simultaneous readings of ground voltage on tower footings and on the pipe line. They consisted also of readings of these ground voltages taken simultaneously with vacuum tube voltmeter readings between two copper sulfate electrodes placed in the earth at various spacings and configurations with respect to the tower footings and the pipe line.

One of the significant tests made involved taking simultaneous walkie-talkie radio communicated readings of tower footing ground voltage, pipe line ground voltage and earth gradient. These tests showed that there was no correlation in the natural variations of the measured quantities, although the earth gradient observation showed that considerable magnitudes of stray fluctuating direct current existed in the earth.

Inasmuch as the characteristics of the soil around the pipe line were ideal to support concentration corrosion, the conclusion was reached that corrosion had been caused by this local action and not by the rectification of induced alternating current.

### Test Coupons

To determine the rate of corrosion on buried steel coupons in the area of the leak under different conditions, 12 accurately weighed and cleaned 3-inch x 6-inch coupons were buried at pipe line depth in a straight line paralleling and approximately three feet distant from the pipe line. Spacing between coupons was approximately three feet.

The coupons should be considered as being numbered consecutively from 1 to 12. With reference to this system, coupons, 1, 4, 7 and 10 were buried without connections to each other or to the pipe line. Coupons 2, 5, 8 and 11 were linked by means of a No. 12 copper wire but were not connected to the pipe line. Coupons 3, 6, 9 and 12 were linked together and this group was connected to the pipe line. The average weight of these coupons was 111.3 grams at time of burial. The average percentage weight loss of coupons 1, 4, 7 and 10 (the unconnected group) was 1.82 percent. The average weight loss of coupons 2, 5, 8 and 11 (the connected group) was 2.45 percent. The average percentage weight loss of coupons 3, 6, 9 and 12 (the group connected with each other and with the pipe line) was 15.50 percent.

Date of burial of coupons was April 29, 1954 and the date of removal was September 23, 1954—an elapsed time of approximately five months. Tests showed that the pipe line was predominantly positive to earth at the leak location.

### Test Ground Bed

In order to determine if cathodic protection would be feasible by rectifying the induced alternating current, a test ground bed was set out. This ground bed consisted of eight ⅝-inch x 4-foot copperweld ground rods spaced at ten-foot intervals in a line at right angles to the pipe line with the first rod set at about 200 feet. A selenium rectifier stack with a rating of 25 amperes and 18 volts was connected between the pipe line and the test ground bed through an ammeter.

The resulting half-wave rectification of the induced alternating current caused a direct current flow of two amperes. This magnitude of direct current flow resulted in a ground voltage change per ampere of test current between pipe and earth at the measuring and regulating station of approximately 0.40 volt/ampere at the main line tap of approximately 0.35 volt/ampere; and at the leak location of approximately 0.43 volt/ampere.

A site for a permanent ground bed installation was selected with particular attention paid to the matter of accessibility and right of way availability. The soil resistivity when checked at this site was found to be 250 ohms/cubic centimeter. Electrical measurement of the rectified voltage between pipe line and the test ground bed at this location showed that approximately five volts direct current would be available for cathodic protection.

### Calculations and Measurements

Recording charts of pipe line ground voltage showed that the maximum exposure condition that must be corrected was approximately 0.6 volt; by simple calculation it was determined that approximately 1.4 amperes of cathodic protection current would be required. Since the galvanic potential difference or back emf between a graphite ground bed and a steel pipe line is usually approximately one volt, an actual value of two volts was assumed for ground bed design. Thus, only three volts of rectified AC voltage would be available for cathodic protection current. It followed then that the curcuit resistance between pipe line and permanent ground bed, including the rectifier stack, should be not more than approximately 2.1 ohms.

A selenium rectifier stack rated at 5 amperes and 15 volts direct current was purchased. It was found by measurement that the forward resistance at a current flow of 1.5 amps was approximately 1.8 ohms. Knowing this it was easy enough to determine that to obtain a total circuit resistance of 2.1 ohms, the resistance of the ground bed and connecting cable should not exceed 0.3 ohms.

Dwight's equations[1] were used in other calculations. It was found that a permanent ground bed consisting of ten 3-inch x 60-inch graphite rods spaced at 24-foot intervals, and 500 feet of 1/0 copper cable could be expected to provide a circuit resistance of the required value.

Actual installation was relatively simple. A rectifier stack rated at 5 amperes and 15 volts direct current was mounted in a weathertight shop-made steel box which had been put into place on a pipe pole adjacent to the pipe line. The graphite rods were merely pushed vertically into the marshy ground and their pigtail connections tied to the 1/0 header cable running from ground bed to the rectifier. Header cable connections were soldered and then taped. Scotch Fill was used for smoothing the roughness of the solder, US Korona for the rubber tape inner-wrap, and Scotch 33 for the outer-wrap. Scotch Kote, was painted over the entire joint to act as a sealer.

After the final connections were made and the installation placed into service, it was found that the

closed circuit, direct current voltage was approximately 2.80 volts. It was found also that the direct current flow varied between 1.36 and 1.43 amperes at time of observation.

This installation was placed in service on September 23, 1954. The press of other work has not permitted further detailed study of the operation other than the setting of periodic recording charts which indicate that the unit is affording the desired amount of cathodic protection as originally designed. When time permits, additional tests will be conducted to determine whether or not polarization of the pipe line will allow for a decrease in the current output of the unit.

## Reference

1. H. B. Dwight. Calculation of Resistance to Ground. *Electrical Engineering*, **55**, 1319-1328, (1936) Dec.

***Any discussions of this article not published above will appear in the June, 1956 Issue.***

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A Technical Note

# Nomograph for Corrosion Rate Calculations*

By HENRY K. BASS, JR.* and ROBERT V. ANDREWS**

**Abstract**

A nomograph which facilitates the determination of corrosion rate in mils per year is described. A typical problem involving calculation of corrosion rate is worked out on the accompanying nomograph.

THE RATE of corrosion of various metals and alloys may be expressed in several ways. The confusion which has arisen as a result of the use of various rate expressions has been clarified somewhat by several nomographs[1,2] and conversion tables[3,4] designed to assist in converting from one rate expression to another.

Recently, however, the universal adoption of the rate expression in mils per year has been advocated.[5] This corrosion rate, MPY, is related to the density of the specimen exposed in grams per cubic centimeter, D; the area exposed in square inches, A; the time of exposure in days, T; and the weight loss of the specimen in grams, W; by the equation:

$$MPY = \frac{22{,}289\ W}{D\ A\ T}$$

This equation may be solved graphically by the

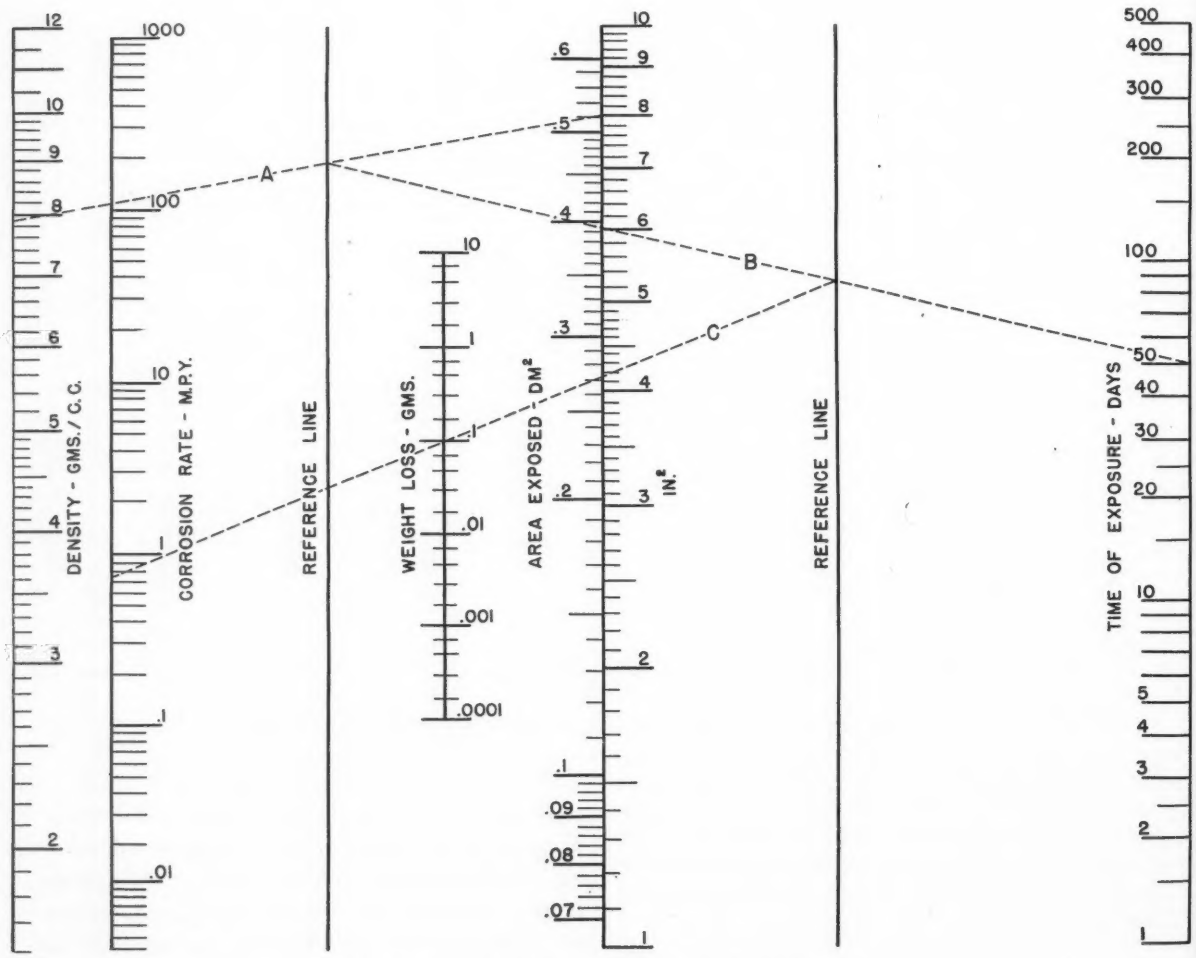


Figure 1—Nomograph used in the calculation of corrosion rates.

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** Lamar State College of Technology, Beaumont, Texas; formerly on the staff of the A and M College of Texas.

accompanying nomograph (Figure 1) simply, rapidly, and with good accuracy.

### A Typical Problem

After exposing a sample of iron (density = 7.86 gms./cc) to a corrosive environment for 50 days, the weight loss by the specimen is 0.10 gram. The area of the exposed surface of the specimen is 8 square inches. What is the corrosion rate?

*Step A:* On the nomograph connect the density, 7.86 gms./cc, with the area exposed, 8 square inches, with a straight edge to intersect the left reference line, as indicated by dotted line A.

*Step B:* From the point of intersection of dotted line A with the left reference line, connect with a straight edge the time of exposure, 50 days, as shown by dotted line B, intersecting the right reference line.

*Step C:* From the point of intersection of dotted line B with the right reference line, connect with a straight edge the weight loss, 0.10 gram, as denoted by dotted line C. The corrosion rate is read as 0.73 MPY where the line C crosses the MPY scale.

For convenience the left side of the area scale is graduated in square decimeters.

### Acknowledgment

All work described in this paper was done at the A and M College of Texas. The assistance of the Texas Engineering Experiment Station is acknowledged in connection with the publishing of this material.

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# High Temperature Hydrogen Sulfide Corrosion*

By E. B. BACKENSTO, R. D. DREW and C. C. STAPLEFORD

## Introduction

IN RECENT YEARS hydrogenation and dehydrogenation processes for upgrading petroleum fractions have become commercial realities in the petroleum industry. These processes operate at high temperatures and hydrogen pressures and usually form hydrogen sulfide which is corrosive under these operating conditions.

It has been known for some time that when hydrogen sulfide corrodes carbon and low chrome steels an iron sulfide corrosion scale is formed. The literature on the separate effects of hydrogen sulfide and hydrogen is voluminous. Limited information is available on the combined effects of hydrogen-hydrogen sulfide.[1,2] These data, however, are based on short term tests, generally at higher pressures and hydrogen sulfide concentrations than are likely to be encountered in the petroleum industry.

Hydrogenation plant experiences served as a forewarning of the seriousness of this problem in catalytic reformers. Nelson[3] defined the sulfide scaling problem and indicated the need for high chrome alloys. On the other hand, however, considerable use had been made in the oil industry of low chrome steels without difficulty in fractionation, catalytic and thermal cracking, and thermal reforming equipment. Therefore, when catalytic reformers were designed, economics appeared to favor low chrome steel construction since the seriousness of sulfide corrosion was not fully understood. For example, the first Thermofor Catalytic Reformer (TCR) was put onstream in the summer of 1954 at the Torrance, California, refinery of General Petroleum Corp. to reform high sulfur naphthas. On inspection after 42 days of operation, deposits up to 0.1-inch thick were found throughout the hot sections of the unit on all types of steel with the exception of 18-8 stainless steel. During this period of operation the process vapors in the unit contained up to about 2 percent hydrogen sulfide by volume.

## Laboratory Tests

The above mentioned experience demonstrated the need for more reliable corrosion data applicable to catalytic reformers. In this connection a laboratory program was initiated to study the corrosion resistance of various steels in hydrogen-hydrogen sulfide atmospheres. This program included tests in commercial reforming units, in laboratory pilot units utilizing hydrogen, and in laboratory corrosion units.

In commercial reforming units, corrosion test racks containing 20-30 coupons of different metals were placed at critical locations; 10 racks were placed in each of two TCR units and 7 racks in each of two Sovaformers. In laboratory pilot units as

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## Abstract

High temperature hydrogen sulfide corrosion of carbon steel and low chrome alloys has become a serious problem in the petroleum industry in connection with the increasing use of high pressure hydrogenation and dehydrogenation processes for upgrading petroleum fractions.

The effect of temperature, pressure and hydrogen sulfide concentration on the corrosion rate of a wide range of commonly used carbon steels and alloys has been determined in laboratory tests. It has been established that the low chrome alloys (up to 5 percent chromium) which have been used to combat sulfur corrosion in fractionation and cracking equipment, show little or no advanage over carbon steel in resisting attack by hydrogen sulfide. Of the conventional alloy steels tested, only the 18-8 chrome nickel and higher alloys have shown good resistance to this type of corrosion over a wide range of pressure, temperature and hydrogen sulfide concentration. It was found that aluminum coated steels also showed very good corrosion resistance.

Three methods were proposed for minimizing hydrogen sulfide corrosion: (1) Reduction of hydrogen sulfide in process streams, (2) Use of chrome-nickel alloys, and (3) Protection of metals by aluminum coating.

many coupons as possible were located, usually in the catalyst bed, in the following type units: naphtha desulfurization and pretreaters, Sovaformers, hydrocrackers, and lube oil hydrotreaters—all of 1 barrel per day capacity—and in an 80 barrel/day fuel oil desulfurization unit. Laboratory corrosion units were constructed of pressure bombs and the auxiliary equipment needed to subject test coupons to a stream of hydrogen-hydrogen sulfide at controlled concentrations, temperatures, and pressures.

More than 80 runs, each including 15-25 different test coupons, were made in these corrosion units covering the following ranges of conditions: 0.002-1.0 percent hydrogen sulfide by volume, 500-1300 F, and 0-500 psig hydrogen pressure. After each test the coupons were descaled and weighed; the metal weight loss was used to calculate the corrosion rates (expressed as inches of penetration per year).

If the sulfide scale is affixed tightly to the metal walls, it may offer some resistance to further corrosion. But if the scale is somehow jarred loose or flakes off during shutdowns due to differences in thermal expansion of the scale and metal, the exposed fresh metal becomes susceptible again to rapid corrosion, and the dislodged scale may cause serious pressure drop difficulties and, ultimately, plugging.

This problem may be understood better by referring to Figure 1 which shows a typical laboratory test coupon. The scale formed on the 9 percent chrome steel in only 3 weeks at 826 F and 460 psig. The corrosive atmosphere was Kuwait naphtha vapor containing 0.085 percent hydrogen sulfide by volume and 11.1 hydrogen by volume. This is typical of the corrosion for carbon steels and chrome steels containing up to 12 percent chrome when exposed at these conditions. The corrosion rates for these metals were between 0.02 and 0.03 inch per year. No evidence of scale was found on the chrome-nickel stainless steels in this test.

Chemical analyses of the metals used in the experiments reported in this paper are summarized in Table 1.

**Figure 1—Corrosion of 9 percent chrome steel laboratory test coupon in hydrogen-hydrogen sulfide atmosphere. The coupon measures 1½ x ½ x ¼ inches. Average test conditions were as follows: temperature—826 F; pressure, psig—460; length of test in hours, 559; gaseous atmosphere data: Kuwait naphtha, percent by volume—88.8; hydrogen sulfide, percent by volume—0.085; hydrogen, percent by volume—11.1.**

Typical behavior of chrome steels under hydrogen-hydrogen sulfide corrosion at 1175 F and 175 psig is shown in Figure 2. The corrosion rate is plotted against the chrome content of the test metals; the lower numbers represent straight chrome steels while the high chrome contents represent chrome-nickel alloys of 18-8, 25-12, and 25-20. The corrosion rates increase with the hydrogen sulfide concentration, particularly for the low chrome steels. Rate curves usually drop off rapidly in the 7-16 percent chrome range.

For all tests made to date, the chrome-nickel alloys consistently have provided the best corrosion resistance while the carbon and low chrome steels have

**TABLE 1—Chemical Analyses of Metals Used in Corrosion Tests**

| DESCRIPTION | Supplier | Heat Number | CHEMCIAL ANALYSES (Balance Fe), Percent Weight | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | C | Cr | Ni | Mo | Mn | P | S | Si | Al | Cu | Ta | Cb | Ti |
| Carbon Steel— | | | | | | | | | | | | | | | |
| ASTM A7 | Morris, Wheeler & Co. | ..... | 0.20-0.35 | ..... | ..... | ..... | ..... | 0.10 Max. | 0.05 Max. | ..... | ..... | ..... | ..... | ..... | ..... |
| ASTM A83—Type A | Hill Chase | ..... | 0.06-0.18 | ..... | ..... | ..... | 0.27-0.63 | 0.048 Max. | 0.058 Max. | ..... | ..... | ..... | ..... | ..... | ..... |
| ASTM A201—Grade A | Morris, Wheeler & Co. | 23522K | 0.19 | ..... | ..... | ..... | 0.48 | 0.010 | 0.024 | 0.20 | ..... | ..... | ..... | ..... | ..... |
| ASTM A285—Grade C | Morris, Wheeler & Co. | 13412 | 0.16 | ..... | ..... | ..... | 0.38 | 0.014 | 0.040 | ..... | ..... | ..... | ..... | ..... | ..... |
| 1 Cr—½ Mo | Timken Roller Bearing Co. | 14856 | 0.10 | 0.97 | ..... | 0.55 | 0.36 | 0.011 | 0.014 | 0.25 | ..... | ..... | ..... | ..... | ..... |
| 1¼ Cr—½ Mo | Timken Roller Bearing Co. | 17990 | 0.09 | 1.20 | 0.27 | 0.53 | 0.50 | 0.013 | 0.014 | 0.70 | ..... | ..... | ..... | ..... | ..... |
| 2¼ Cr—1 Mo | Timken Roller Bearing Co. | 23237 | 0.11 | 2.36 | 0.24 | 1.02 | 0.30 | 0.018 | 0.017 | 0.34 | ..... | ..... | ..... | ..... | ..... |
| 5 Cr—½ Mo | G. O. Carlson Co. | RO-45485-6A | 0.06 | 4.96 | 0.10 | 0.49 | 0.39 | 0.023 | 0.023 | 0.31 | ..... | ..... | ..... | ..... | ..... |
| 7 Cr—½ Mo | Timken Roller Bearing Co. | 23379 | 0.125 | 6.35 | 0.15 | 0.54 | 0.36 | 0.014 | 0.025 | 0.84 | ..... | ..... | ..... | ..... | ..... |
| 9 Cr—½ Mo | Timken Roller Bearing Co. | 11977 | 0.11 | 8.03 | 0.48 | 0.97 | 0.48 | 0.019 | 0.011 | 0.68 | ..... | ..... | ..... | ..... | ..... |
| 12 Cr—Type 405 | G. O. Carlson Co. | 52426-2A | 0.048 | 12.47 | 0.30 | ..... | 0.76 | 0.016 | 0.015 | 0.51 | 0.22 | ..... | ..... | ..... | ..... |
| 12 Cr—Type 410 | G. O. Carlson Co. | 54034-1A | 0.069 | 12.71 | 0.31 | 0.44 | 0.39 | 0.018 | 0.017 | 0.39 | ..... | 0.14 | ..... | ..... | ..... |
| 16 Cr—Type 430 | G. O. Carlson Co. | 54137 | 0.088 | 17.82 | 0.33 | ..... | 0.58 | 0.020 | 0.014 | 0.46 | ..... | 0.12 | ..... | ..... | ..... |
| 25 Cr—Type 446 | G. O. Carlson Co. | A46849 | 0.15 | 26.14 | 0.32 | ..... | 0.83 | 0.026 | 0.019 | 0.70 | ..... | ..... | ..... | ..... | ..... |
| 18-8—Type 302 | Allegheny | 42950 | 0.086 | 17.57 | 8.71 | ..... | 0.85 | 0.028 | 0.022 | 0.41 | ..... | 0.23 | ..... | ..... | ..... |
| 18-8—Type 304 | G. O. Carlson Co. | 64343-2B | 0.055 | 18.56 | 9.42 | ..... | 0.67 | 0.030 | 0.025 | 0.44 | ..... | 0.25 | ..... | ..... | ..... |
| 18-8—Type 304L | G. O. Carlson Co. | 64541-2B | 0.028 | 18.29 | 9.44 | ..... | 1.09 | 0.024 | 0.013 | 0.39 | ..... | 0.19 | ..... | ..... | ..... |
| 18-8—Type 316 | G. O. Carlson Co. | 64073-1C | 0.041 | 17.78 | 12.93 | 2.42 | 1.84 | 0.023 | 0.017 | 0.70 | ..... | 0.20 | ..... | ..... | ..... |
| 18-8—Type 316L | G. O. Carlson Co. | 64307-2 | 0.019 | 17.60 | 13.80 | 2.75 | 1.50 | 0.021 | 0.019 | 0.55 | ..... | 0.34 | ..... | ..... | ..... |
| 18-8—Type 317 | G. O. Carlson Co. | 44562 | 0.074 | 18.64 | 13.68 | 3.22 | 1.75 | 0.024 | 0.019 | 0.55 | ..... | 0.24 | ..... | ..... | ..... |
| 18-8—Type 321 | Allegheny | 52064 | 0.05 | 17.42 | 10.55 | ..... | 1.54 | 0.024 | 0.025 | 0.95 | ..... | 0.32 | ..... | ..... | 0.34 |
| 18-8—Type 347 | Republic | 625526 | 0.054 | 17.75 | 10.75 | ..... | 1.80 | 0.028 | 0.017 | 0.55 | ..... | ..... | ..... | 0.94 | ..... |
| 25-12—Type 309 | G. O. Carlson Co. | 54580-24 | 0.060 | 22.24 | 14.62 | ..... | 1.93 | 0.020 | 0.014 | 0.46 | ..... | 0.17 | ..... | ..... | ..... |
| 25-12—Type 309CBS | G. O. Carlson Co. | 53785-2D | 0.057 | 23.05 | 15.48 | ..... | 1.81 | 0.021 | 0.019 | 0.52 | ..... | ..... | 0.08 | 0.54 | ..... |
| 25-20—Type 310 | G. O. Carlson Co. | 54038-1B | 0.060 | 24.76 | 20.07 | ..... | 1.25 | 0.021 | 0.015 | 0.55 | ..... | 0.12 | ..... | ..... | ..... |

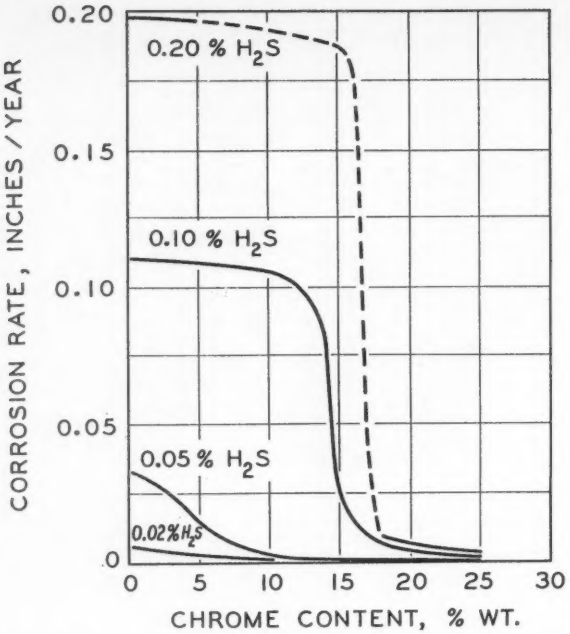


Figure 2—Corrosion rate of chrome steels in hydrogen sulfide at 1175 F and 175 psig hydrogen pressure.

exhibited the poorest corrosion resistance. The intermediate group of 7-16 percent chrome steels are unpredictable; at most conditions they are usually no better than the lower chrome steels—at mild conditions they show increasing resistance with chrome content. The authors have not obtained any significant differences in corrosion rates between carbon steels and steels containing up to 5 percent chrome.

Under certain conditions, as will be shown later, no significant difference in corrosion rate was found for the group of 0-9 percent chrome steels.

Additional information on the effect of hydrogen sulfide concentration is summarized in Figure 3. As can be seen, the corrosion rates drop off rapidly with a decrease in hydrogen sulfide concentration. At the same conditions as shown in Figure 3, additional 3-week runs were made at hydrogen sulfide concentrations of 0.002, 0.004, and 0.006 percent by volume. The data are not plotted at these low concentrations inasmuch as the corrosion rates are extremely low.

## Scaling

The authors' main interest in these low hydrogen sulfide concentration runs was to determine at what point actual scaling occurred. A thin film of powdery corrosion products appeared on steels containing up to 2¼ percent chrome at 0.006 percent hydrogen sulfide by volume and this type of corrosion was evident for all steels containing up to 9 percent chrome at 0.01 percent hydrogen sulfide by volume. In no case at the low concentrations was there evidence that scale would form on the chrome-nickel alloys. From observations made in the laboratory it is known that flaky corrosion scale generally forms on steels which exhibit corrosion rates of about 0.01-0.02 inch per year or higher, regardless of chrome content. Generally the scale is less flaky and more tightly adhering for the high chrome alloys.

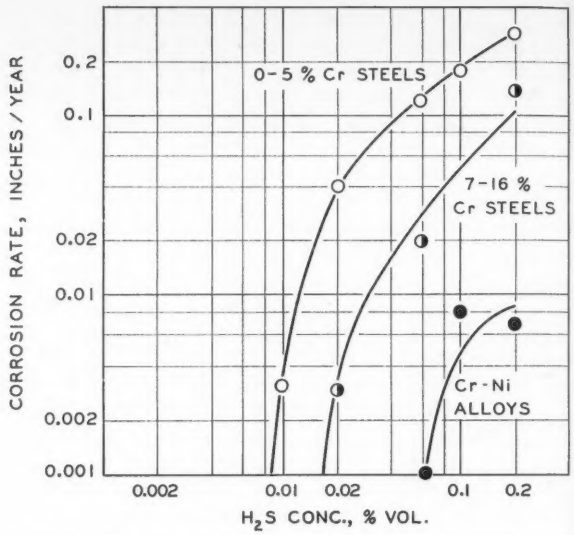


Figure 3—Effect of hydrogen sulfide concentration on corrosion rate at 985 F and 485 psig hydrogen pressure.

Typical corrosion test results are shown in Table 2. In this test the effluent gases from the pressure bomb were passed through a second bomb maintained at atmospheric pressure. Note the good agreement in the corrosion rate results for the group of 0-7 percent chrome steels and the group of chrome-nickel alloys. As in other tests, the corrosion rate differences are insignificant among the group of chrome-nickel alloys tested. In general, increasing the amount of alloy from 18-8 to 25-12 or 25-20 improves the corrosion resistance slightly. No definite advantage has been shown for extra low carbon or stabilized stainless steels over the more conventional types.

**TABLE 2—Typical Corrosion Test Results**

| **Average Conditions** | | |
|---|---|---|
| Temperature, °F | 850 | 850 |
| Hydrogen Pressure, psig | 0 | 485 |
| $H_2S$, Percent Volume in $H_2$ | | |
| Inlet | 0.087 | 0.111 |
| Outlet | 0.081 | 0.087 |
| Length of Test, Hours | 224 | 224 |
| **Material Tested** | **Corrosion Rate (Inches per Year)** | |
| Carbon Steel—ASTM A7 | 0.0351 | 0.107 |
| Carbon Steel—ASTM A-83-A | 0.0494 | 0.127 |
| Carbon Steel—ASTM A-201-A | 0.0415 | 0.095 |
| 1 Cr—½ Mo | 0.0400 | 0.117 |
| 2¼ Cr—1 Mo | 0.0394 | 0.108 |
| 5 Cr—½ Mo | 0.0376 | 0.0918 |
| 7 Cr—½ Mo | 0.0343 | 0.0988 |
| 12 Cr—Type 405 | 0.0238 | 0.0178 |
| 12 Cr—Type 410 | 0.0234 | 0.0239 |
| 16 Cr—Type 430 | 0.0146 | 0.0154 |
| 18-8—Type 302 | 0.0041 | 0.0074 |
| 18-8—Type 304 | 0.0034 | 0.0052 |
| 18-8—Type 304L | 0.0032 | 0.0059 |
| 18-8—Type 347 | 0.0031 | 0.0056 |
| 25-12—Type 309 | 0.0031 | 0.0025 |
| 25-12—Type 309CBS | 0.0022 | 0.0022 |
| 25-20—Type 310 | ..... | 0.0018 |

Corrosion rate determinations on the same type metal in triplicate are reported in Table 3. These data demonstrate the accuracy and reproducibility of the test data reported.

In laboratory tests, exposure time of test coupons is extremely important when attempting to obtain practical corrosion rate data. Figure 4 is a plot of corrosion rates for 0-9 percent chrome steels vs exposure time. Each point on this plot represents an individual test. The points are not rate measurements on the same coupons at different exposure times. The number of individual corrosion rate determinations averaged for each point is indicated within the circle. Each corrosion rate included in the average deviated less than 25 percent from the number reported. The corrosion rate is high after 24 hours and drops off rapidly to about 100 hours; thereafter, the rate drops off slowly. This shows that the sulfide scale offers some protection against further corrosion. Most of the authors' laboratory tests, unless specified, were of 150-200 hours duration; tests at very low hydrogen sulfide concentrations were generally longer—about 400-500 hours. It is felt that the data obtained in this manner show conservatively high corrosion rates.

Because of the fact that a wide variety of conditions are encountered in the operation of refining processes, it becomes important to know the effect of the major variables on sulfide corrosion. According to data in Figures 2 and 3 the corrosion rate increases with hydrogen sulfide concentration. This same effect is shown in Table 4 for hydrogen sulfide partial pressures from 0.25 to 1.0. With the exception of the chrome-nickel alloys, the corrosion rates increase, but not linearly, with partial pressure. At the two total pressures shown there are no significant differences in corrosion rates at the same hydrogen sulfide partial pressure. Note that these results are for short-term tests, therefore the corrosion rates should be used for comparative purposes only.

The effect of hydrogen sulfide partial pressure is not as pronounced in longer term tests, especially at higher pressures (see Figure 5). It may be noted in that Figure that the corrosion rate increases to about 200 psia and then tends to level off. The corrosion rates for the chrome-nickel alloys were not plotted on Figure 5 inasmuch as they were low and showed no trend.

**TABLE 3—Corrosion Rate Determinations in Triplicate**

| | |
|---|---|
| **Average Conditions** | |
| Temperature, °F | 986 |
| Hydrogen Pressure, psig | 484 |
| **$H_2S$, Percent Volume in $H_2$** | |
| Inlet | 0.10 |
| Outlet | 0.08 |
| Length of Test, Hours | 24 |

| Material Tested | Corrosion Rate (Inches per Year) |
|---|---|
| Carbon Steel—ASTM A285-C | 0.629 |
| Carbon Steel—ASTM A285-C | 0.625 |
| Carbon Steel—ASTM A285-C | 0.630 |
| 5 Cr—½ Mo | 0.639 |
| 5 Cr—½ Mo | 0.648 |
| 5 Cr—½ Mo | 0.660 |
| 7 Cr—½ Mo | 0.592 |
| 7 Cr—½ Mo | 0.635 |
| 7 Cr—½ Mo | 0.635 |
| 9 Cr—½ Mo | 0.552 |
| 9 Cr—½ Mo | 0.535 |
| 9 Cr—½ Mo | 0.581 |
| 12 Cr—Type 405 | 0.382 |
| 12 Cr—Type 405 | 0.352 |
| 12 Cr—Type 405 | 0.459 |
| 16 Cr—Type 430 | 0.229 |
| 16 Cr—Type 430 | 0.225 |
| 16 Cr—Type 430 | 0.232 |
| 18-8—Type 321 | 0.0594 |
| 18-8—Type 321 | 0.0636 |

**TABLE 4—Effect of $H_2S$ Partial Pressure on Corrosion Rate**

| $H_2S$ Partial Pressure, psi | 0.25 | 0.5 | 0.5 | 1.0 |
|---|---|---|---|---|
| Total $H_2S$ & $H_2$ Pressure, psig | 235 | 485 | 235 | 485 |
| **Materials** | **Corrosion Rate (Inches per Year)** | | | |
| 0—5% Cr | 0.49 | 0.64 | 0.63 | 0.81 |
| 7—16% Cr | 0.36 | 0.46 | 0.49 | 0.58 |
| Cr—Ni | 0.07 | 0.06 | 0.07 | 0.07 |

(24 Hour Tests at 985° F.)

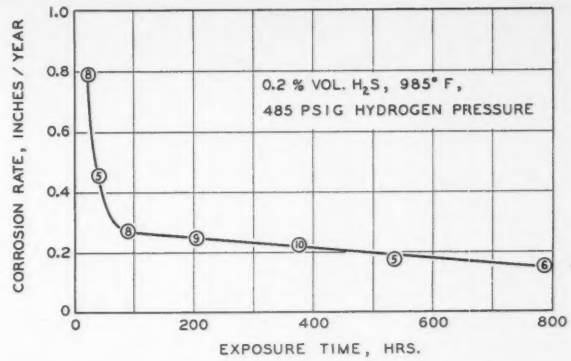


**Figure 4—Effect of exposure time on corrosion rates of 0-9 percent chrome steels. The number of individual measuremnts averaged is shown within the circle.**

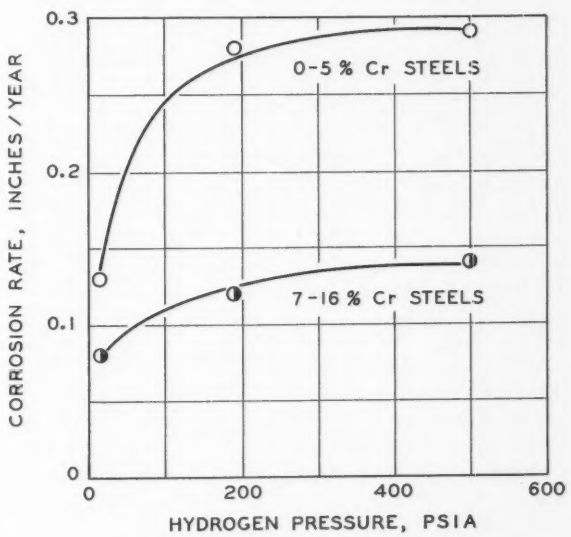


**Figure 5—Effect of hydrogen pressure on corrosion rate at 985 F and 0.2 percent by volume hydrogen sulfide.**

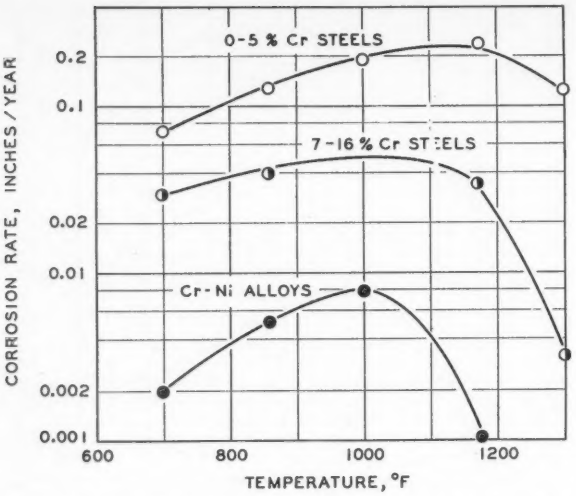


Figure 6—Effect of temperature on corrosion rate at 0.1 percent by volume hydrogen sulfide and 485 psig hydrogen pressure.

### Effect of Temperature

Temperature is another important variable as can be seen from examining Figure 6. For most conditions below 500 F hydrogen sulfide atmospheres are not very corrosive. Above 500 F the corrosion rates increase rather rapidly to 1000 F. At about 1000 to 1200 F the corrosion rate appears to reach a maximum and then drops off with further increase in temperature. The temperature at which this maximum is reached appears to depend on the type of metal; it is approximately 1200 F for the carbon and low chrome steels and somewhat less as the chrome content of the metal is increased.

Data presented on the effects of hydrogen sulfide concentration and temperature cannot be used indiscriminately for estimating corrosion rates at other conditions. Figure 7 shows the effect of temperature at higher hydrogen sulfide concentrations than reported in Figures 2 and 3. It is noted that the effect of concentration is not consistent over the entire temperature range studied. For example, at 500 F the corrosion rates at 0.8 percent hydrogen sulfide by volume are about eight times the rates obtained at 0.3 percent hydrogen sulfide by volume; at 600-735 F there are no significant differences in corrosion rates between 0.3 and 0.8 percent hydrogen sulfide by volume.

Corrosion rates reported so far have been obtained from test coupons subjected to various atmospheres of hydrogen-hydrogen sulfide. A three-week run was made in the laboratory to simulate naphtha furnace conditions by pumping a mixture of Kuwait naphtha vapor, 0.085 percent hydrogen sulfide by volume, and 11.1 percent hydrogen by volume through a 5 percent chrome tube in a gas-fired furnace. During this test the 5 percent chrome tube formed scale nearly 1/64-inch thick. This scale was analyzed and found to contain 62 percent iron which means essentially iron sulfide and no coke. Photographs of furnace tube sections in Figure 8 show the flakiness of the scale after cooling; data for this figure are contained in Table 5.

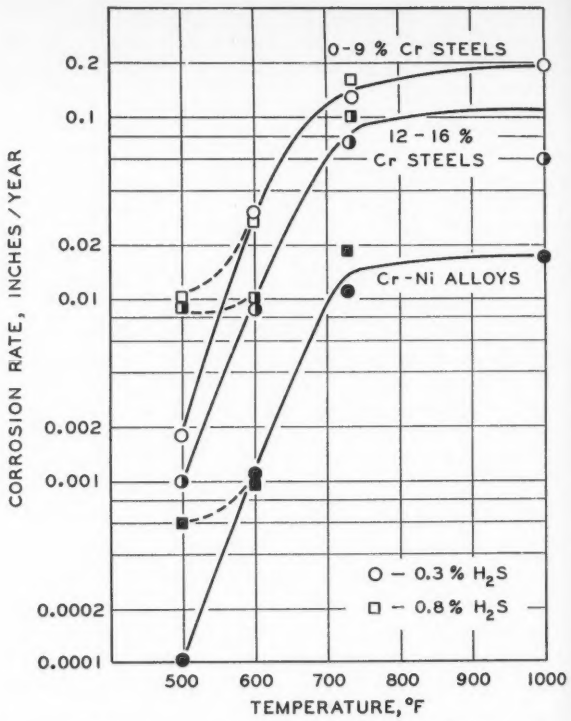


Figure 7—Effect of temperature and concentration on hydrogen sulfide corrosion at 465 psig hydrogen pressure.

Gas velocity often has an important effect on corrosion rate; however, the authors in their studies of hydrogen sulfide corrosion found no significant differences in corrosion rate due to gas velocity over a wide range.

There are probably many other things that affect sulfide corrosion rate. Some of these other variables that were studied to a limited extent are discussed below:

1. *Specimen Pretreatment*
   - **a.** Pretreating the metal specimens with hydrogen for as long as 68 hours does not affect their corrosion resistance. This indicates that no increase in corrosion rate should be noted in commercial equipment if it is necessary to pressure-test or start-up with a hydrogen atmosphere.
   - **b.** Pretreating with air to form a thin oxide film on the metals increases the corrosion rate by about 25 percent on short term tests. This increase may be a result of metal loss from the oxide formation.
2. *Diluent for Hydrogen Sulfide*

   The diluent gas for hydrogen sulfide also affects the corrosion rate. For example, corrosion rates are lower in nitrogen than in a hydrogen atmosphere. There are indications from tests in pilot units that the presence of naphtha also suppresses corrosion rate to some extent. However, minor components in the naphtha, such as chlorides, acids, or nitrogen compounds may have

adverse effects on the corrosion rate; these effects have not been explored as yet.

3. *Moisture*

The addition of 0.2 percent water by volume to a hydrogen-hydrogen sulfide atmosphere increased the corrosion rate by about 10-15 percent, but the addition of 3 percent water did not increase the corrosion rate further. There were some indications, however, that not all metals respond to the effect of moisture in the same manner. It should be pointed out that these observations are based on only three experiments and further work will be necessary to more fully establish the effect of moisture.

## Hydrogen Blistering

The question of hydrogen blistering always arises when dealing with corrosion in hydrogen atmospheres. Under the conditions covered in this study, however, this matter does not appear to be a major problem. Thus among approximately 2,000 test coupons subjected to hydrogen sulfide corrosion (of which more than 300 were of carbon steel) only two specimens showed evidence of hydrogen blistering. In both cases the coupons were composed of ASTM A201-A steel. The conditions were as follows:

1. 0.0044 percent hydrogen sulfide by volume 987 F, 485 psig hydrogen pressure, 18.5 days.
2. 0.0101 percent hydrogen sulfide by volume 986 F, 485 psig hydrogen pressure, 23.3 days.

Figure 9 shows evidence of this blistering for the first condition mentioned above. The corrosion rate measured for the specimen shown was 0.0015-inch per year.

From the previous discussion it appears that there are two possible ways to minimize hydrogen sulfide corrosion—the choice depending on economic considerations. One alternative involves the use of chrome-nickel stainless steels. The other method centers around the reduction of hydrogen sulfide concentration in the environment. (This can be accomplished by the desulfurization of the charge stock to the process or by removal of hydrogen sulfide from recycle gas streams.) A third method is the protection of metal surfaces by coating with aluminum.

A run was made at 0.2 percent hydrogen sulfide by volume, 1200 F, 175 psig hydrogen pressure, for 18.2 days to test various aluminum coatings. The following types of coatings were included in this test:

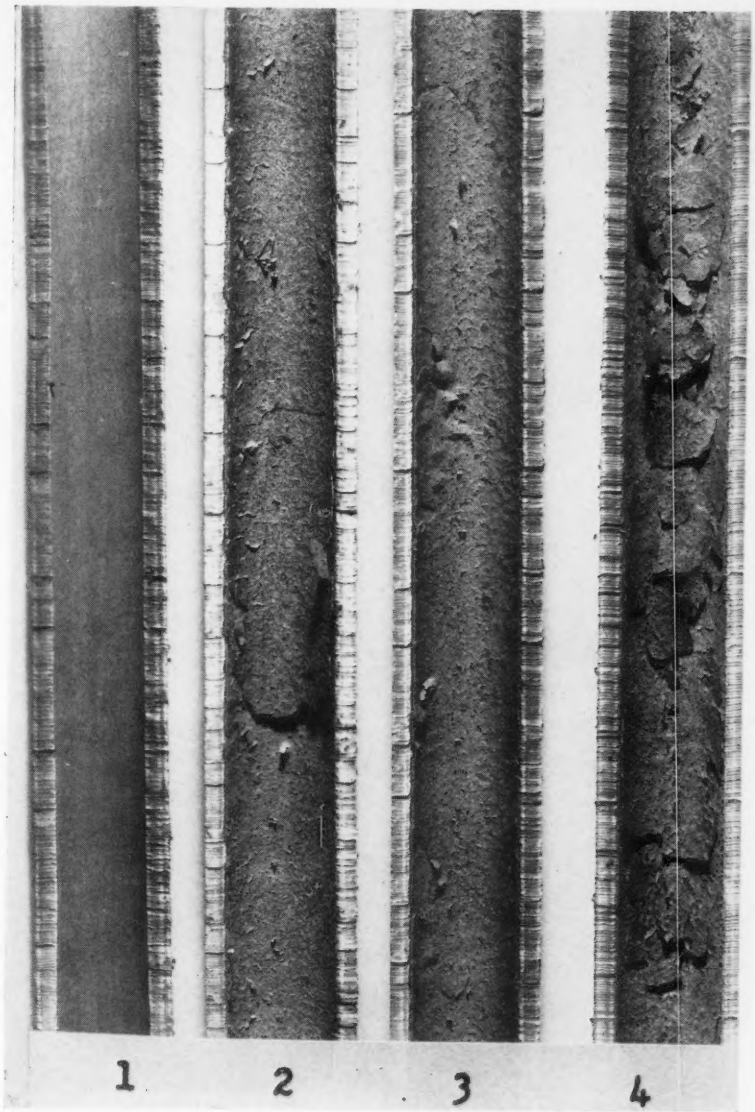


Figure 8—Furnace tube (B and W Croloy 5, ⅜-inch Sch. 40) sections after three-week test at 460 psig. Furnace charge—Kuwait naphtha vapor containing 0.085 percent by volume hydrogen sulfide and 11.1 percent by volume hydrogen.

TABLE 5—Data for Specimens Pictured in Figure 8

| Section Number | Average Temperature, Degrees, F. | | Corrosion Rate Inches per Year |
|---|---|---|---|
| | Tube Skin | Naphtha | |
| 1* | ... | ... | .... |
| 2 | 876 | 645 | 0.035 |
| 3 | 859 | 711 | 0.026 |
| 4 | 905 | 770 | 0.044 |

* Blank.

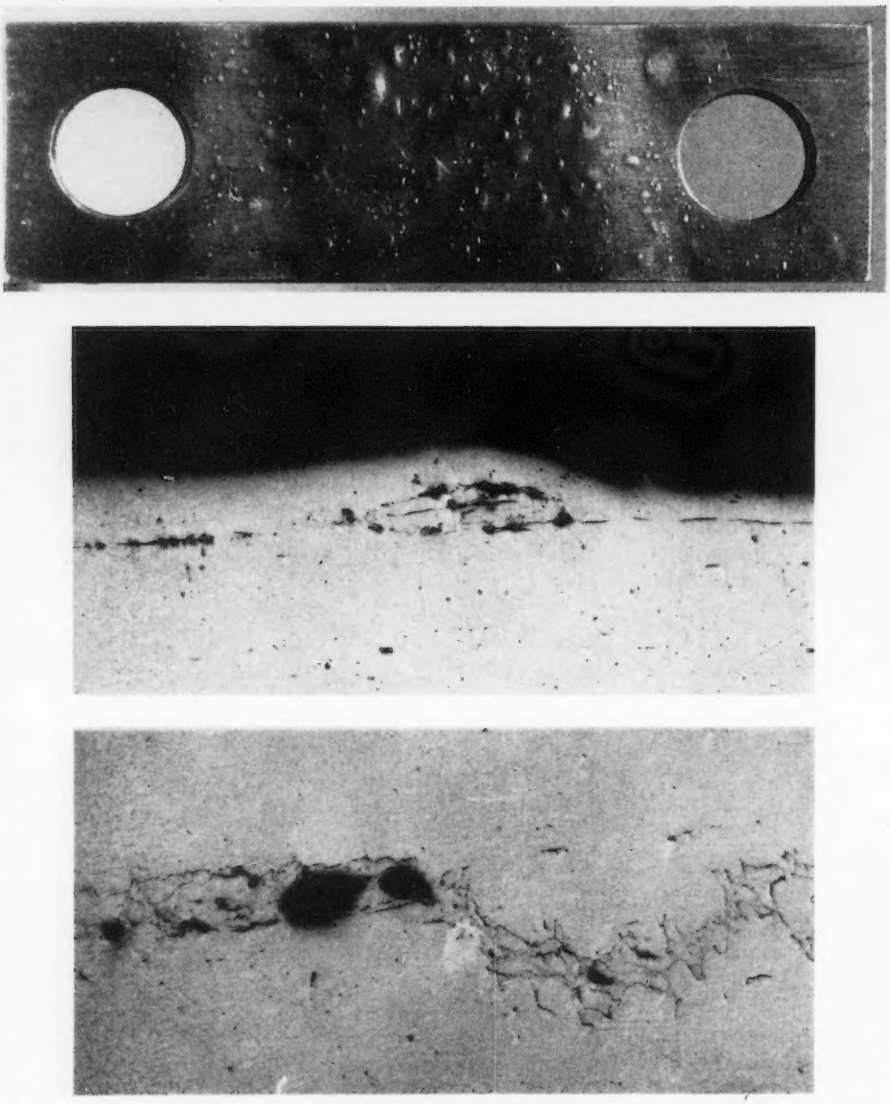

Figure 9—Evidence of high temperature hydrogen blistering in a hydrogen-hydrogen sulfide atmosphere (ASTM A201-A carbon steel at 0.0044 percent by volume hydrogen sulfide, 987 F, 485 psig hydrogen pressure. Top photograph shows a blistered steel specimen, 3.5X. In the middle is a photomicrograph, 100X, unetched, of cross section showing cracking and blister caused by hydrogen diffusion and subsequent hydrogen pressure in discontinuities immediately below the surface. At the bottom is a photomicrograph, 100X, unetched, of cross section showing cracking due to hydrogen pressure in voids considerably below surface.

1. Calorized (an aluminum diffusion process) carbon steel.
2. Several aluminum dipping processes on carbon steels and steels containing up to 7 percent chrome.
3. Metallized aluminum of different thicknesses on a low chrome steel.

### Calorized Carbon Steel

At the conditions described above only calorized carbon steel showed no attack. The aluminum overlay and most of the bond material disappeared for the metallized and aluminum dipped specimens. With the exception of the calorized specimen (and regardless of base metal used) some grain growth was noted after the test in the base metal along the surface that had been coated.

Calorized carbon steel has consistently passed laboratory sulfide corrosion tests. In addition to the conditions cited above, calorized specimens showed no apparent attack after 55 days exposure to 0.5 percent hydrogen sulfide by volume at 935 F and 175 psig hydrogen pressure. At lower hydrogen sulfide concentrations, for test periods as long as 33 days, this type of coating has been satisfactory up to 1000 F and 500 psig hydrogen pressure.

Figure 10 shows photomicrographs of calorized carbon steel specimens exposed to different corrosive atmospheres; data for this figure are contained in Table 6. The photo on the left shows no attack under

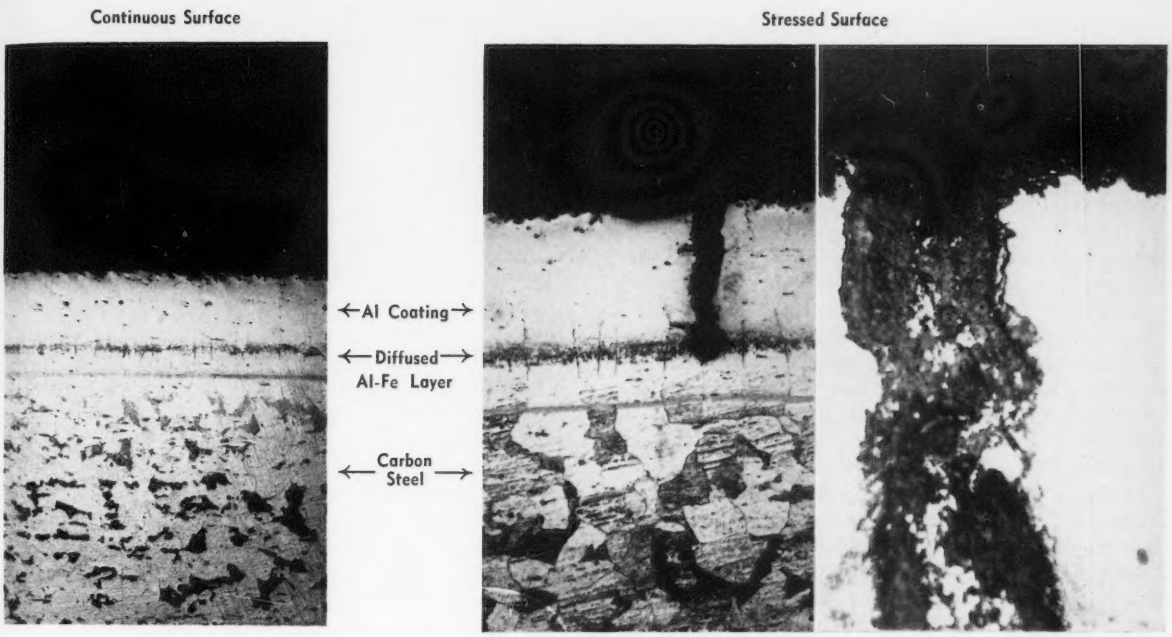


Figure 10—Photomicrographs of Calorized carbon steel specimens exposed to different corrosion atmospheres. At left is photomicrograph, 50X, where no apparent attack of coating is shown. In the middle photomicrograph no apparent attack of coating is shown; crack extends nearly to base metal (100X). At right is a photomicrograph, 250X, of one of the other cracks in the same specimen showing crevice filled with corrosion products.

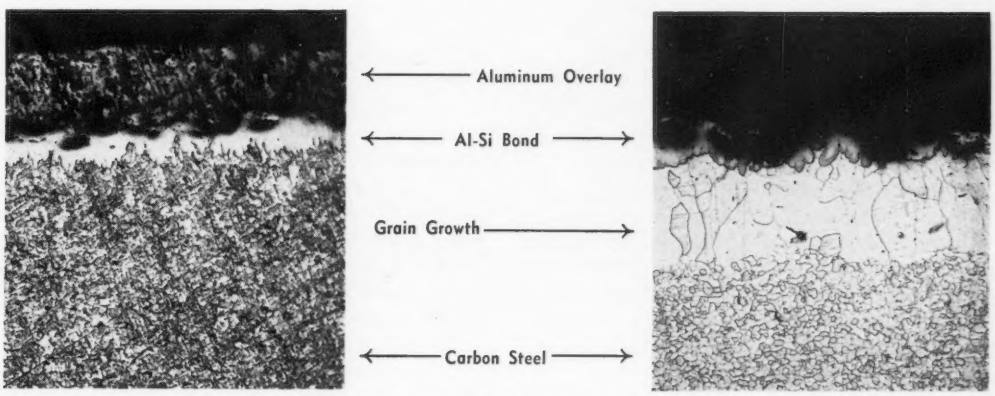


Figure 11—Photomicrographs of aluminum dipped carbon steel specimens exposed to different corrosive atmospheres. Both photomicrographs are 50X, Nital etch.

**TABLE 6—Data for Specimens Pictured in Figure 10**

| Average Test Conditions | Continuous Surface(1) | Stressed Surface(2) |
|---|---|---|
| $H_2S$, Percent Volume in $H_2$ | 0.046 | 0.024 |
| Temperature, F | 985 | 985 |
| Hydrogen Pressure, psig | 485 | 485 |
| Exposure Time, Hours | 178 | 154 |

(1) Photograph on left.
(2) Photograph in middle and on right.

**TABLE 7—Data for Specimens Pictured in Figure 11**

| Average Test Conditions | Left Photo | Right Photo |
|---|---|---|
| $H_2S$, Percent Volume in $H_2$ | 0.20 | 0.10 |
| Temperature, Degrees F | 985 | 1175 |
| Hydrogen Pressure, psig | 485 | 175 |
| Exposure Time, Hours | 77 | 154 |

the test conditions. The photos on right show a specimen that was purposely stressed to produce small cracks in the coating prior to the test. Note that the crack shown extended nearly to the base metal but that the aluminum overlay remained intact.

The photo on the extreme right is a higher magnification of one of the other cracks in the same specimen and shows it to be filled with corrosion products even at the mild corrosive conditions of the test. This information shows the importance of maintaining a continuous coating if calorizing is expected to give satisfactory service in hydrogen-hydrogen sulfide atmospheres.

Laboratory tests of less than 10 days have shown that aluminum dipped carbon steel shows no visible attack for conditions up to 1000 F and 500 psig

hydrogen pressure. At the same conditions, longer term tests (20-35 days), however, showed that the aluminum overlay disappeared. The tests showed also that if the test period were long enough, even the bond material disappeared leaving the steel unprotected.

At temperatures of 600-700 F, aluminum dipped carbon steel has afforded satisfactory protection for test periods as long as 55 days. Figure 11 shows photomicrographs of aluminum dipped carbon steel specimens exposed to different corrosive atmospheres; data for this figure are contained in Table 7. The photo on the left shows no attack under the test conditions for a relatively short term test. The photo on the right shows nearly complete loss of overlay and bond material. The grain growth noted at the high temperature may have contributed to the failure of the coating.

In the case of the TCR unit corrosion problem mentioned in the beginning of this report, a number of changes were made. An amine scrubber was installed to lower the hydrogen sulfide content in the recycle gas to about 0.03 percent by volume. All the hot transfer lines were calorized and critical sections of the reactor and kiln were replaced with 18-8 stainless steel. The unit was put back on-stream and brought down after 55 days of operation for a corrosion inspection. This inspection showed that the unit was in excellent condition; it was put back in operation without further changes.

## Conclusions

In conclusion, results reported from laboratory, pilot and commercial units have shown that hydrogen sulfide corrosion can be a serious problem in the petroleum industry. Measures must be taken to combat this type of corrosion when processing petroleum stocks with hydrogen at high temperatures and pressures. Three methods for minimizing hydrogen sulfide corrosion have been proposed: reduction of hydrogen sulfide in process streams, the use of chrome-nickel alloys, and the protection of metals by aluminum coating.

## Acknowledgment

The authors express their appreciation to J. E. Prior, of Socony Mobil Oil Company's laboratories, who conducted the metallographic examinations in connection with this work.

## References

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## DISCUSSION

**Discussion by Elmore M. Peloubet, Arthur Tickle Engineering Works, Inc., Brooklyn, N. Y.:**

We have definite data which indicates that after exposures to high temperature hydrogen sulfide corrosion in an actual petroleum installation for a total of more than 2,000 hours there was no decrease in the effectiveness of the aluminized coating in overcoming high temperature hydrogen sulfide corrosion. The protective ability of a hot-dip aluminized coating on carbon steel, on mild alloy steel, or even the high alloy stainless type of steels, is dependent upon the formation of a complex intermetallic alloy layer which is metallurgically bonded to the base steel.

This intermetallic alloy layer (more commonly known as a "diffused layer") is the end result of the diffusion of the overlay of pure aluminum or the aluminum alloy resulting from the hot-dipping operation diffusing into the steel at elevated temperatures, thereby forming these highly complex intermetallic alloys of iron and aluminum. This resultant diffused alloy layer is very similar to the so-called calorized layer or coating as applied by the normal calorizing process.

### Interpretation of Photomicrographs

The authors refer to Figure 11, showing a photomicrograph of aluminum dipped carbon steel specimens which were exposed to hydrogen sulfide corrosion at elevated temperatures. Their interpretation of these photomicrographs is that the aluminum has been completely corroded away leaving the base steel exposed to attack of the hydrogen sulfide. They refer to a layer which they term "grain growth."

It is my opinion that this is a complete misinterpretation of the photomicrograph. I believe that this so-called "grain growth" area is actually the diffused layer of intermetallic iron aluminum alloys which has resulted from the aluminum overlay diffusing into the base steel. The formation of this diffused bond layer or interfacial layer will vary according to many factors; namely, the times and temperatures of the aluminum dipping operation, the type of steel being dipped, and the aluminum alloy which is used for the aluminum dipping operaion.

As a matter of fact, it is perfectly feasible (and it is being done on a commercial basis) to obtain a "calorized" coating using the hot-dip process followed by a suitable diffusion heating process.

The temperature range in which the authors conducted their investigation is suitable for causing this transformation of the free aluminum overlay into the diffused interfacial bond layer consisting of the complex intermetallic compounds of iron and aluminum. Naturally the degree of this transformation will depend upon the time and temperature of the actual operation.

In the case studied by the authors, the temperature and hours of exposure mentioned in the text and Table 7 (985F and 77 hours, 1175F and 154 hours) will be sufficient to cause this diffusion to occur. I would be especially interested to learn the following: Did the authors actually determine if there was corrosion of the base steel itself or did they believe the beneficial effects of an aluminum coating had disappeared with the disappearance of the shiny characteristic color of the aluminum coating; was the test sufficient to definitely indicate corrosion would occur with the disappearance of the aluminum and appearance of the so-called "grain growth" (see Figure 11);

and was sufficient data obtained by further exposure to confirm this conclusion.

### Use of Silicon

Another important point for the discussion of the protection of steels to high temperature hydrogen sulfide corrosion by hot-dip aluminizing is the consideration of the aluminum alloy actually used for the application of the coating. It has been definitely established that the addition of certain elements to an aluminum bath will reduce the formation or act as a barrier to the formation of this intermetallic alloy layer. One of the most effective such additives is silicon. The use of silicon in the hot-dip aluminizing bath not only effectively decreases the formation of the intermetallic layer during the actual hot-dipping process, but it also continues its effectiveness in reducing the formation of the diffused layer obtainable by subsequent high temperature heat treatments which are conducted in order to purposely establish this diffused layer.

We have found that the use of silicon in the aluminum bath has a barrier effect. It is recommended by us to any prospective user of hot-dip aluminized coatings in the petroleum field for the protection of steels to the attack of hydrogen sulfide that they use commercially pure aluminum with a definite maximum limit on silicon contact. We do not know whether or not these particular specimens as tested by the authors were formed from an aluminum silicon alloy, but we must assume this inasmuch as in Figure 11, they refer to the Al-Si Bond.

In connection with the use of the aluminum silicon alloy, the transformation of the overlay and the actual bond layer as obtained during the dipping operation into a completely diffused layer will take place more rapidly at a lower temperature than if pure aluminum had been used for the hot-dip coating. Likewise, the closer the actual operation temperatures to 1200F, the more rapidly the aluminum silicon overlay will diffuse. This is due to the fact that the aluminum silicate eutectic actually will be molten at temperatures in the neighborhood of 1100F.

Under the conditions of the tests conducted by the authors, I definitely would suspect that at the 1175F test conditions the aluminum silicon alloy actually was in a molten condition. As stated before, this definitely would tend to increase the rapidity with which the diffusion would occur and naturally would result in "disappearance" of the aluminum overlay.

### Additional Tests

In view of excellent success obtained by other petroleum companies using hot-dip aluminized coatings for protection against high temperature hydrogen sulfide corrosion, and in view of the fact that the authors of this paper in their concluding paragraph state that three methods for minimizing hydrogen sulfide corrosion have been proposed (reduction of hydrogen sulfide in process streams, the use of chrome nickel alloys, and protection of metals by aluminum coating), I believe that additional tests are warranted. Such tests should definitely establish whether or not hot-dip aluminized coatings will be beneficial in overcoming hydrogen sulfide corrosion over longer periods of time, or at least for a sufficient period of time to be satisfactory for the petroleum industry in general.

**Discussion by Heinrich Heep, The M. W. Kellogg Company, Jersey City, New Jersey:**

High temperature hydrogen sulfide corrosion is a very timely subject of wide interest. The authors and company with which they are connected have made a real contribution to the petroleum industry in publishing this excellent paper.

Valuable information is presented on corrosion rates of the most used analyses of steel in atmospheres of different concentration of either hydrogen sulfide or of hydrogen sulfide and hydrogen, and under variations of pressure, temperature and length of exposure. Test results summarized in Tables 2 to 4 and Figures 2 to 8 provide useful information for those generally interested in this type of corrosion. In particular, conditions characteristic of catalytic reforming processes were simulated in the tests and interesting data derived.

Of special interest among the conclusions in the paper is the experimental corroboration of the fact that corrosion resistance against hydrogen sulfide is raised in a stepwise, rather than proportional, fashion as the percentage of chrome in steel is increased. Thus the low chrome and chrome-molybdenum steels do not possess better resistance to hydrogen sulfide corrosion than carbon steel and one has to go to the 12 percent to 16 percent chromium group to appreciably lower the corrosion rates.

### Comparative Data

The reviewer feels that the tables and graphs fail to present comparative data on steel with various types of protective aluminum coatings. Have such data been collected or did the authors derive their qualitative conclusions regarding the value of these protective coatings from microphotographs as depicted in Figures 10 and 11? If the latter is the case the validity of the conclusions must be questioned, inasmuch as those photographs seem to have been misinterpreted.

For instance, Figure 11 shows a sample of aluminum dipped carbon steel after 77 hours exposure. Approximately 0.010 inch metallic aluminum remains bonded to the steel by means of a layer of about 0.0025 inch iron-aluminum alloy. The reviewer estimates from the small thickness of the diffused layer that 2½-5 percent Al-Si alloy was used in the preparation of the sample. Silicon is a deterrent to diffusion and consequently a thinner metallurgical bond results as compared with the use of pure 99 plus percent aluminum.

Another dip-coated specimen shown in Figure 11 experienced a 154 hours exposure at 1175F. Most of the aluminum overlay is diffused into the steel as indicated by the growth of the iron-aluminum diffusion zone. However, the authors misinterpreted this as grain growth and complete removal not only of the aluminum overlay, but also of the diffused layer, leav-

ing the bare steel unprotected. The reviewer believes that the photos actually show a diffused aluminum coating comparable to a calorized surface as shown in Figure 10.

The reviewer also disagrees with the explanations of Figure 10. For instance, the approximately 0.015 inch layer described as aluminum coating actually is diffused iron-aluminum alloy characteristic of calorized surfaces. Such aluminum overlay, if it existed, would be ductile and unlikely to crack in the fashion shown on the right. It is the brittle alloy which tends to crack.

In essence the reviewer believes that the photomicrographs disprove the unfavorable conclusions of the authors regarding hot-dip aluminum coatings, which also do not agree with field experiences. In this connection, the reviewer wishes to mention that more than 1000 feet of hot-dip aluminum coated pipe was engineered and installed by his company during the construction of the 3000 BPD Ultraformer for American Oil Company in Texas City. After being on stream approximately 2100 hours, the aluminized surfaces appeared to be standing up well against hydrogen sulfide corrosion, while unprotected surfaces, although subjected to a less corrosive condition, were badly attacked.

**Reply by E. B. Backensto to discussions:**

We appreciate the comments by Mr. Peloubet and Mr. Heep. Since both men raise similar questions, we shall attempt to clarify our results.

The supplier of the aluminum dipped specimens was familiar with our problem and with the fact that these test pieces would be run in a hydrogen-hydrogen sulfide atmosphere. We were told that these contained a 12 percent Si-Al bond layer. We understand that in cooperation with the supplier our company arrived at a specification for aluminum dipped material of one mil bond and four mil overlay minimum thickness.

Perhaps the terms used in our paper to describe aluminum dipped specimens are not those generally accepted in the industry. We believe, however, that the terms used are clearly defined by pictorial reference. What we called grain growth was just that, regardless of how it came about. Since we did not test this growth area for aluminum, we could not definitely call this aluminum diffusion.

For calorized specimens we should not have referred to an aluminum overlay; we realize that calorizing is a diffusion process wherein the outer surface is richest in aluminum, with the aluminum content decreasing with depth. The notations on Figure 10 were for convenience in our evaluation. The term "diffused Al-Fe layer" does not properly define this area. The dark line on the photomicrographs, which appears to be a needle-like crystalline structure, is probably an Fe-Al intermetallic compound. From our experience we have noted that this area shows up only after exposure to hydrogen-hydrogen sulfide at high temperatures.

We should point out that for aluminum dipped specimens, the test pieces were cut from a larger aluminized plate; therefore, only two large faces of the coupon were coated, while base metal was exposed on all smaller sides. Using this procedure, the test conditions are more severe. It was felt that such a test would represent extreme field conditions where it might be possible to break or impair the coating during fabrication of the unit. For calorized specimens, two mounting holes were drilled through a coated specimen, exposing base metal at these points.

Considering the way the specimens were prepared, there was no accurate way to measure base metal weight loss for the aluminum coated specimens. In our tests the disappearance of overlay and bond, by any means, was considered a failure. We arrived at this conclusion since in many cases where the overlay was no longer present after exposure, a film of corrosion product was present.

In one of our tests, two similar dipped specimens were included. One of these was cut for metallographic inspection and showed complete loss of overlay. The other specimen from this test was not examined metallographically but was placed in another test run. After the second test period, the aluminum dipped specimen was scaled nearly to the extent of fresh carbon steel in the same test. Furthermore, we know of an actual commercial installation at intermediate temperature where in less than two months service the aluminum dipped coating spalled off and iron sulfide corrosion scale covered the base metal.

**Hot-Dip Aluminum Coated Pipe**

We appreciate knowing that hot-dip aluminum coated pipe is showing good protection in reformer service. The reason this experience differs from ours may be due to the type of annealing or surface preparation used. In a paper by Kremer and Volk on "Production and Use of Heat Resisting Aluminum Coating" (Stahl und Eisen, Vol. 66-67, pp. 250-255, 1947), it is pointed out that scaling resistance of hot-dip aluminized parts can be improved considerably by a diffusion heat treatment at 1900-2000F. The authors also point out that at high temperatures the aluminum diffuses into the base metal and decreases the effectiveness of the coating.

We feel that all types of aluminizing may find application in this field and we agree that our work suggests additional tests on aluminum coatings. We hope that our paper has pointed out the need for more information on these coatings, from both the suppliers and users. Also, since there are many techniques for alumininzing, it would be extremely advantageous to have more information on the various types, their application in reformer service, their limitations of application, and the recommended methods of surface preparation and where and when these methods can be applied.

***Any discussions of this article not published above will appear in the June, 1956 issue.***

# Correlation of the Results Obtained With Corrosion Inhibitors in the Laboratory and in the Field*

By G. E. PURDY and WILLIAM J. RIES

## Introduction

IT IS SURPRISING that the first paper discussing the serious internal corrosion problems occurring in gas-condensate wells was presented as late as 1943.[1] Similarily, the problem of sour oil well corrosion, while long recognized, was not definitely attacked until the formation of the "Sour Oil Well Corrosion Committee," TP-1D early in 1950.[2] In general, most internal corrosion problems in the oil industry were accepted as a necessary evil and little was done.

Early use of inorganic and organic corrosion inhibitors was largely unsatisfactory in the inhibition of oil well corrosion.[3] The discovery that formaldehyde could be used effectively as an inhibitor in sour crude areas and the development of synthetic organic inhibitors, which could be effectively and economically used, undoubtedly served to point out the seriousness of corrosion where it had not been recognized before.[3,4]

Initially the task of coping with these corrosion problems was usually the minor responsibility of the field engineer. Later on more attention was given to the question of overall costs in relation to personnel requirements. Ultimately the assignment was made of individuals qualified to investigate and evaluate the many factors responsible for corrosion in oil wells and the available methods of corrosion inhibition.

One of the principal duties of the oil field corrosion engineer is the evaluation of a certain particular approach to a corrosion problem. When the situation calls for it he must be able to select one single approach from several that may be suited to his problem. In a number of instances he may have available certain data or information from his company's research laboratory or from various published sources.

In the final analysis the corrosion engineer must in some way assign a particular value to whatever method he chooses to use in combating corrosion problem. For many cases this may be extremely difficult and may require a careful study of factors not readily apparent. It is the purpose of this paper to indicate some of the ways by which this may be accomplished, and to show some of the difficulties encountered in evaluating organic corrosion inhibitors for combating internal oil well corrosion.

## Factors Which Influence Corrosion Rate

### *A. Effect of Water*

As corrosion is an ionic chemical reaction, it is necessary that water be present in the oil well fluids for corrosion to occur. It has been observed that water is found in some degree with all the petroleum produced. From field to field the amount of water may vary from more than 99 percent to less than 0.1 percent.

These produced waters are found to contain a great number of dissolved substances.[5] The common metal ions included are those of sodium, potassium, calcium, magnesium, barium, etc. Anions such as chlorides, sulfates, sulfides, carbonates, nitrates and

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## Abstract

One of the responsibilities of the oil field corrosion engineer is to correlate laboratory and field test data. With this in mind the principle factors which influence internal corrosion in oil wells (factors which the corrosion engineer must consider) are reviewed here.

A laboratory corrosion test method is discussed. Corrosion rate data obtained in the laboratory with three West Texas crude oil and brine systems and the corrosion inhibition obtained in these systems with two organic inhibitors are analyzed and compared. Field corrosion test data for the same three fields are presented. The correlation of laboratory and field test data is discussed in relation to the many variables encountered.

It is concluded that the evaluation of the use of inhibitors in some cases may be difficult and may require considerable experience and judgment on the part of the corrosion engineer.

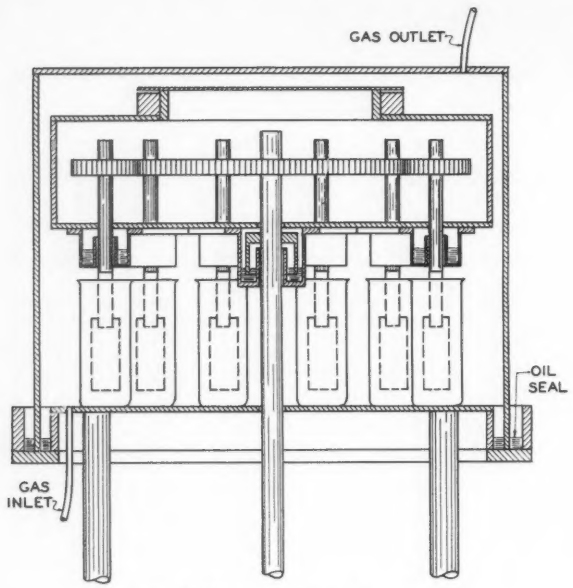


Figure 1—Half section corrosion test apparatus.

others usually are present. Also, a number of water soluble organic compounds may be found.

The presence of the ions mentioned above can affect the corrosion rate in various ways; for example, the amount of dissolved salts largely determines the electrical conductivity of the water, and thus may accelerate corrosion or enable a wider separation between local anodes and cathodes.

Acids may be dissolved in water. As a general rule, the lower the pH value the greater the expected corrosion rate. It is not unusual to find hydrochloric, hydrosulfuric, carbonic, acetic, propionic and other acids in oil field brines. In fact, it generally is concluded that internal corrosion in the primary production of oil is essentially an acid reaction.

*B. Effect of Oil*

As the produced water will vary in composition, the oils produced also will vary widely in composition. Aside from the common differences of gravity and other physical characteristics, oils are known to contain certain trace polar organic compounds which may affect the corrosion rate.

Dr. H. L. Lochte of the University of Texas isolated high molecular weight organic acids, phenols, ketones, and organic bases.[6,7] Lochte postulated that the presence of these compounds may inhibit corrosion by producing an oil-wetted surface which would mask the metal from the water phase.

A number of oil fields have been observed where all the factors that influence corrosion are such that one would expect corrosion to occur. Actually, however, little or none of this is actually observed. Some Wyoming fields, for example, produce a large percentage of water, the gases contain up to 15 percent hydrogen sulfide and the water definitely is acidic. Yet in five years of production no detectable corrosion has been observed. Laboratory data clearly indicate the presence of certain corrosion inhibiting constituents in these oils.

*C. Effect of Gases*

The principal gases which affect the corrosion rate are hydrogen sulfide, carbon dioxide, and oxygen.[8] Both hydrogen sulfide and carbon dioxide when dissolved in water become acids which are recognized as the principal causative corrosive agents in oil well corrosion. Oxygen acts to accelerate the corrosion rate because of its ability to react with other components in the produced fluid. Oxygen may react to form acids, or it may react with hydrogen formed at the cathode to cause depolarization.

*D. Effect of Temperature and Pressure*

The corrosive action of acid gases is dependent upon the solubility of these gases in water. The solubility of the gas increases with a drop in temperature and a rise in pressure. The temperature also affects the ionization constant of dissolved salts.

*E. Velocity*

The velocity of the corrosive media affects the movement of the causative agents over the metal surface resulting in a continuation of the corrosion process. The velocity of the media also acts to remove the hydrogen formed at the cathode, thus causing depolarization. The corrosion products formed at the anode may be removed by the velocity of the well fluids resulting in a continuation or even acceleration of the corrosion rate. Where adsorption type corrosion inhibitors are used, velocity will move additional inhibitor to areas where the inhibitor has been de-adsorbed.

## Laboratory Test Procedure

For the purpose of this paper, the study of corrosion occurring in a normal pumping sour oil well will be undertaken.

In order to evaluate properly or study the effect of corrosion inhibitors in the laboratory, actual well conditions should be duplicated in the laboratory test as closely as possible. The laboratory test therefore should include the "factors which influence corrosion rate" which have been previously discussed. In other words, the test should be a dynamic test with a three phase system of oil, water, and gas with controlled temperature conditions and regulated partial pressures of the gases.

This adopted test method has been presented to the T-1K Committee and was described in detail by Greco and Spalding in Appendix L of their paper "Laboratory Methods for the Evaluation of Inhibitors for Use in Oil and Gas Wells."[9] A sectional view of the corrosion test apparatus is shown in Figure 1. The test method is essentially one in which weighed metal coupons which have been immersed in beakers containing ratios of a selected oil and water are rotated. The entire apparatus is enclosed in an atmosphere containing regulated partial pressures of hydrogen sulfide, carbon dioxide, and nitro-

gen or any combination thereof. The temperature is thermostatically controlled.

## Laboratory Evaluation of Corrosion Rate

### *A. Effect of Oil-Water Ratio*

One of the factors which commonly has been recognized as generally influencing the corrosion rate is the effect of the oil-water ratio. Figure 2 illustrates laboratory test data indicating the corrosion rate obtained at various oil-water ratios with oil and water obtained from the McElroy Pool (Grayburg Lime) at Crane, Texas; the World Pool (San Andres Lime) at Big Lake, Texas; and the Howard Glasscock Pool at Big Spring, Texas. It is observed that the maximum corrosion rate varies from field to field and no general rule can be stated for the existence of a corrosive condition based solely on the percentage of water present.

In the case of the McElroy field the maximum corrosion rate occurs at a ratio of approximately 30 percent oil and 70 percent water. This rate is noticeably greater than if either water or oil alone were present. Severe corrosion, however, was present at all oil-water ratios.

With the oil and water from the World Pool, the ratio apparently has very little effect on the corrosion rate. At all of the oil-water ratios, the corrosion rate is about the same.

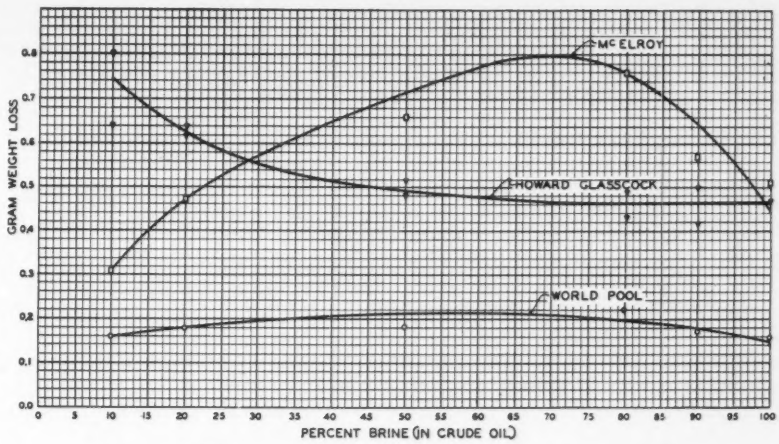


Figure 2—Laboratory corrosion rates in various oil-water ratio systems.

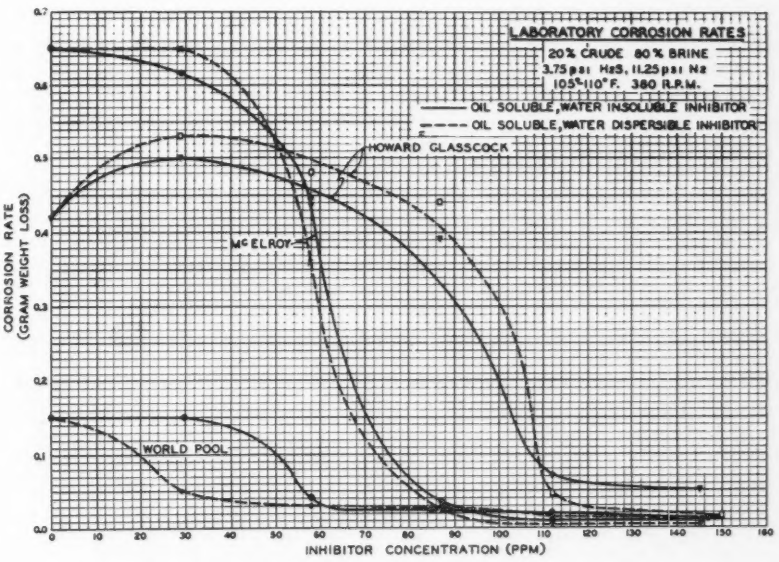


Figure 3—Laboratory corrosion rates with two types of organic inhibitors.

The maximum corrosion rate for the Howard Glasscock field oil and water system seems to occur at some point where less than 10 percent water is present. This fact is substantiated to some degree by field experience. The dehydrated crude gathering lines and pipe lines leading into the Cosden Refinery, Big Spring, Texas, have been noted for the frequency of leaks due to internal corrosion prior to the time the field was treated with corrosion inhibitors.

### *B. Mitigation with Organic Inhibitors*

Figure 3 illustrates the effect of adding two organic corrosion inhibitor formulas, one oil-soluble water-insoluble and the other oil-soluble water-dispersible, at varying concentrations to a system of 20 percent crude oil and 80 percent brine from the West Texas fields described. In all tests, sand-blasted 1020 carbon steel test coupons were rotated at a rate of 380 rpm, at a temperature of 105-110 F. for a period of approximately 70 hours. The atmosphere surrounding the system was controlled to contain 25 percent hydrogen sulfide and 75 percent nitrogen with a total gas rate of 500 cc/minute.

Evaluation of the laboratory test data obtained with the McElroy crude oil and brine system indicates that the use of organic inhibitors reduces the corrosion rate at all concentrations until a concentration of approximately 90 ppm (based on total fluids) is reached. At greater concentrations, undoubtedly, an excess of inhibitor is present over that necessary for the complete adsorption of a protective film. It is interesting to note from the field data subsequently to be presented that from 80 to 100 ppm of the inhibitor were required for protection in the field tests. This fact substantiates the results of the laboratory test method.

The laboratory results obtained with the World

Pool system also indicate the inhibitor reduced the corrosion rate to some degree at all concentrations. The use of the oil-soluble water-dispersible inhibitor approached a degree of maximum protection at lower concentrations than the oil-soluble water-insoluble inhibitor, although both formulations of inhibitor finally achieved the same degree of protection.

The results obtained with the Howard Glasscock system indicate a behavior widely different from the other systems in that at lower concentrations of the inhibitor an accelerated corrosion rate is observed. The effect is not clearly understood. It is believed that organic corrosion inhibitors generally are adsorbed on metallic surfaces and not first adsorbed at either local anodes or cathodes.

Blair commented[10] that this laboratory has observed that corrosion under some conditions may be accelerated by oil-wetting (either natural occurring or by use of certain wetting agents) of the metallic surface. It appears that a "hydrogen-ion" cell may be established between certain oil-wet and water-wet areas. In effect, the water-wet areas become cathodic because of ready availability of hydrogen ions while the oil-wet areas become anodic because of a deficiency of hydrogen ions. The overall effect is to increase the corrosion rate to a greater degree than that observed if the metal surface were either entirely oil or water-wetted.

A possible explanation may be that, at the lower inhibitor concentrations, a partial oil- or water-wetting occurs to cause the accelerated corrosion rate effect. This is presented merely as a possibility inasmuch as a complete investigation of this effect has not been undertaken.

Actual corrosion mitigation programs with these inhibitors in the various fields indicate a substantiation of the amount of inhibitor that was required in the laboratory test method to obtain optimum protection. A typical well in the World Pool, for example, produces 122 barrels of oil and 207 barrels of water daily. Treatment with one quart of organic inhibitor daily has proven to be successful. Based on total fluids this is a treating rate of approximately 20 ppm. The laboratory test data indicate a concentration of approximately 30 ppm would be required.

In the Howard Glasscock field a typical treatment consists of three quarts of inhibitor for a well producing 36 barrels of oil and 85 barrels of water, or at a rate of approximately 150 ppm. Laboratory test data indicate that at least 110 ppm of inhibitor is required for maximum protection.

**TABLE 1—Corrosion Survey, McElroy Field**

| Test Period | Inhibitor Conc. (ppm—Total Fluids) | Coupon Corrosion Rate (mpy) | Rod Jobs | Tubing Jobs |
|---|---|---|---|---|
| 3/31— 4/14/47 | 0 | 7.97 | .. | 2 |
| 4/16— 4/30/47 | 0 | 2.31 | .. | 1 |
| 4/30— 5/14/47 | 0 | 3.85 | 12 | .. |
| 5/14— 5/28/47 | 0 | 13.4 | 2 | .. |
| 5/28— 6/11/47 | 0 | 9.19 | 2 | .. |
| 6/13— 6/27/47 | 0 | 8.50 | 1 | .. |
| 6/27— 7/11/47 | 0 | 6.99 | .. | 1 |
| 7/11— 7/25/47 | 59.3 | 1.21 | .. | .. |
| 7/25— 8/ 8/47 | 68.4 | 0.65 | 1 | .. |
| 8/ 8— 8/22/47 | 55.0 | 0.49 | 1 | .. |
| 8/22— 9/ 5/47 | 40.3 | 0.77 | .. | .. |
| 9/ 5— 9/19/47 | 33.3 | 2.18 | 1 | .. |
| 9/19—10/ 3/47 | 66.1 | 0.36 | 1 | .. |
| 10/ 3—10/31/47 | 34.1 | 3.30 | 5 | .. |
| 10/31—11/14/47 | 34.7 | 2.80 | .. | .. |
| 11/14—11/28/47 | 0 | 1.75 | .. | .. |
| 11/28—12/12/47 | 0 | .. | .. | .. |
| 12/26/47—1/9/48 | 55.4 | 1.13 | .. | 1 |
| 1/23— 2/ 6/48 | 27.1 | 5.90 | .. | .. |
| 2/ 6— 2/20/48 | 28.2 | 1.25 | 2 | 1 |
| 2/20— 3/19/48 | 22.2 | 5.16 | .. | .. |
| 3/19— 4/ 2/48 | 41.2 | 0.38 | 1 | .. |
| 4/ 2— 4/16/48 | 24.3 | 0.54 | .. | .. |
| 4/16— 4/30/48 | 27.9 | 1.33 | 1 | .. |
| 4/30— 5/14/48 | 25.1 | 4.66 | 3 | 1 |
| 5/14— 5/28/48 | 0 | 19.70 | 2 | .. |
| 5/28— 6/11/48 | 0 | 25.60 | .. | .. |
| 6/11— 6/25/48 | 0 | 12.90 | .. | .. |
| 6/25— 7/10/48 | 0 | 1.70 | 2 | .. |
| 7/10— 7/26/48 | 0 | 7.37 | .. | .. |
| 7/26— 8/ 7/48 | 0 | 14.00 | 3 | .. |
| 8/ 7— 8/21/48 | 0 | 23.1 | 1 | .. |
| 8/21— 9/ 4/48 | 0 | 6.59 | .. | .. |
| 9/ 4— 9/21/48 | 119 | 1.97 | 1 | .. |
| 9/21—10/ 5/48 | 69.3 | 5.04 | 1 | .. |
| 10/ 5—10/19/48 | 100 | 4.90 | .. | 1 |
| 11/ 3—11/17/48 | 26.7 | 5.70 | 2 | .. |
| 11/17—12/ 1/48 | 24.5 | 6.85 | 1 | .. |
| 12/ 1—12/15/48 | 29.4 | 8.27 | 1 | .. |
| 12/15—12/29/48 | 29.0 | 11.62 | 1 | 1 |
| 12/29/48—1/14/49 | 46.3 | 6.40 | 1 | .. |
| 1/28— 2/11/49 | 63.0 | 2.06 | 1 | .. |
| 2/11— 2/25/49 | 88.3 | 0.69 | .. | .. |
| 3/11— 3/25/49 | 0 | 1.92 | .. | .. |
| 3/25— 4/ 8/49 | 85.7 | 3.89 | .. | .. |
| 4/ 8— 4/22/49 | 88.3 | 0.47 | .. | .. |
| 4/22— 5/ 6/49 | 110 | 0.61 | .. | .. |
| 5/20— 6/ 3/49 | 148 | 0.51 | .. | .. |
| 6/ 3— 6/22/49 | 296 | 0.35 | .. | .. |
| 6/22— 7/ 5/49 | 296 | 0.43 | .. | .. |
| 7/ 5— 7/20/49 | 296 | 1.99 | .. | .. |
| 7/20— 8/31/49 | 148 | 0.30 | .. | .. |

## Field Corrosion Evaluation Data

In order further to correlate the laboratory test results with field experience, the data of a field test in the McElroy Pool started in March, 1947, and extending until August, 1949, are given in Table 1. During the test period of over 2½ years, weighed mild-steel test coupons were installed at a well-head flow line for a corrosion-rate evaluation. A record was maintained of all replacement jobs that were caused by corrosion as could be best determined.

Table 2 is a condensation of Table 1 which permits a study of the cumulative effect of the corrosion

**TABLE 2—Cumulative Corrosion Survey, McElroy Field**

| TEST PERIOD | Average Inhibitor Conc. (ppm) | Average Coupon Rate (mpy) | Rod Jobs for Period | Tubing Jobs for Period | Comments |
|---|---|---|---|---|---|
| 3/31— 7/11/47 | 0 | 7.45 | 17 | 4 | 3½ Month Period |
| 7/11—10/31/47 | 46.9 | 1.28 | 9 | 0 | |
| 10/31— 1/ 9/47 | 43.6 | 1.89 | 0 | 1 | |
| 1/23— 5/14/48 | 27.4 | 2.54 | 7 | 2 | |
| 5/14— 9/ 4/48 | 0 | 13.87 | 8 | 1 | 4 Month Period |
| 9/ 4—12/ 1/48 | 45.0 | 4.89 | 5 | 1 | 5½ Month Period |
| 12/ 1/48— 2/11/49 | 38.4 | 6.48 | 6 | 1 | |
| 2/11— 5/ 6/49 | 92.6 | 1.52 | 0 | 0 | 6½ Month Period |
| 5/20— 8/31/49 | 197.5 | 0.71 | 0 | 0 | |

mitigation program over grouped time intervals of approximately quarter year periods. An attempt was made to maintain specific concentrations of inhibitors during these periods.

### Discussion of Results

A detailed study of the coupon data indicates that despite a reasonable effort on the part of the operators to maintain a specific treating rate with the corrosion inhibitor there was a considerable variation of the coupon corrosion rate. This was due in part to the fact that the daily oil and water production rates fluctuated greatly, resulting in a varied inhibitor concentration.

The corrosion rate also was affected by the variation in the daily oil-water ratio. In fact it was observed, following a work-over, that the well sometimes pumps only water for several days. As has been previously shown, the oil-water ratio may affect the corrosion rate in such a way that test coupons exposed during a short period for an evaluation of the corrosion rate may reflect the corrosion rate existing during the period of exposure, but not the actual corrosion rate that exists over an extended period.

Coupon data, per se, are not quantitative in determining the actual corrosion rate for the basis of calculating the expected equipment life. The test coupon reflects only the corrosion rate at the point of exposure. Coupons which are exposed at the wellhead cannot be expected to reflect the corrosion rate existing at subsurface points where the corrosion rate actually may be many times greater.

Coupon test data, used cumulatively, can serve as a valuable guide for the judging and evaluating of results. This is particularly true since during the early stages of a corrosion inhibition program the frequency of equipment failures is largely dependent upon the corrosive conditions existing prior to treatment. In other words, one cannot use the frequency of replacing subsurface equipment immediately following the use of a corrosion inhibitor as a means of evaluation. This is because rods and tubing might have been damaged previously by corrosion prior to treatment. A considerable period of time may be required to eliminate this accumulated damage.

An analysis of Table 2, which shows average coupon corrosion rate and equipment replacements over long grouped periods of time, indicates that on this basis there is some correlation between the coupon corrosion rate and the actual corrosion loss of the equipment. It must be observed that in order for the data to be valid an analysis must be made over an extended time period. If one were to consider individual data over short periods of time, as illustrated in Table 1, false conclusions undoubtedly could be made.

The data presented in Table 1 and 2 definitely demonstrates that it is extremely difficult in many cases for the corrosion engineer to evaluate a corrosion mitigation program. In many instances, extreme patience by the individual is required because of the fact that it is impossible to control the many variables which may affect the corrosion rate in the field. Therefore, it is impossible for the individual to place a valid evaluation on the effectiveness of the use of an inhibitor over a short period of time. It has been observed, nevertheless, that many individuals do attempt this. For example, Inhibitor A will be used for a 2 or 4 week period followed by Inhibitor B and C and an attempt made to select the proper formulation from the data obtained. It is felt that this approach is a mistake and that no valid interpretation of the test data can be made.

### Conclusions

It is concluded that for the purpose of planning a corrosion inhibition program for the field a proper laboratory test method can be used for the evaluation of organic corrosion inhibitors. The laboratory test data presented demonstrates the possibility of determining the most suitable inhibitor formulation and the required treating rate necessary for corrosion mitigation. The results obtained from actual field experience over a number of years have substantiated these facts.

Considering the factors that influence corrosion, it is concluded that the laboratory test method used for evaluation should as nearly as possible duplicate actual field conditions. In the instance of sour pumping oil wells this method should be dynamic and should involve the use of a three phase system of oil, brine and gas, with controlled temperature and regulated partial pressures of the gases.

The correlation and evaluation of laboratory and field tests are in most cases difficult. The field evaluation of the use of organic inhibitors cannot be made in a short period of time because it is impossible to control conditions which may affect corrosion rate.

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## DISCUSSION

**Question by A. H. Roebuck, Continental Oil Co., Ponca City, Oklahoma:**

If in an oil-water system you consider the water-wet area the anode, and the oil-wet area the cathode, how do you picture the conductance through the liquid media?

**Reply by G. E. Purdy:**

If it is assumed that under certain conditions in a two phase system, consisting of water and oil, the water-wet area is anodic (or cathodic) and the oil-wet area is of the opposite category, then it must be assumed that conductance or ion transfer must occur through the oil-water interface.

To show that this may occur, an interesting experiment conducted by Dr. C. M. Blair, former Director of Research of the Tretolite Laboratories, is described below:

> One hundred ml of distilled water, 100 ml of mineral spirits and 2 ml of glacial acetic acid were placed in a separatory funnel and shaken vigorously for approximately five minutes and then allowed to separate.
>
> Into the left arm of the U tube, which was separated by a semipermeable fritted glass bridge, was placed the aqueous layer. The oil layer was placed into the right arm. In each side were immersed identical 1020 mild steel cylinders freshly sand-blasted and connected via liquid-tight Teflon-covered connector wires to a pH meter used as a galvanometer.
>
> Readings were attempted but the potential was so transient it could not be measured.
>
> Five ml of 95 percent isopropanol was poured into the mineral spirits side of the U tube and mixed. A wire screen shield was placed around the U tube electrode system.
>
> Voltage was found to be steady at —0.65 volts and the aqueous phase was observed to be cathodic with reference to potential. An evolution of hydrogen was observed in the aqueous phase. Potential rose slowly to —0.69 volts.
>
> After standing overnight in a short-circuited condition, the cell was observed. The oil-phase electrode was dark and the oil contained a reddish precipitate. The water-phase electrode was bright and the aqueous solution clear. The cell potential was found to be essentially zero, indicating polarization. After the oil electrode was cleaned by dipping in 10 percent HCl, washing, drying, and reinserting, the potential was observed to be about —0.2 volts but it shortly fell to zero.

The conclusions of this experiment were that, under certain conditions, relatively large potential differences may be built up between oil-wetted and water-wetted portions of steel. It is significant, too, that corrosion occurred, in this instance, in the oil phase.

One may reason that the above development was caused by the formation of a concentration cell. In the water-phase a relatively great concentration of hydrogen ions were present in comparison to the oil phase, even though acetic acid was only weakly ionized. The presence of the greater number of hydrogen ions in the water-phase caused this phase electrode to be cathodic.

This experiment illustrates that conductance through the oil-water interface may occur, although it is conceded that the exact mechanism of transfer is not entirely understood. Undoubtedly the presence of alcohol in the above experiment aided either in increasing the water solubility of the oil, or, in dispersing water into the oil. Without doubt, if the oil were *bone* dry, conductance would not occur at ordinary potentials capable of being formed by an initial corrosion process even though the corrodant were present in both phases.

There are several possibilities by which conductance through the oil-water interface might occur. One possibility is that ionized water particles dispersed in the oil may accomplish this merely by a collision mechanism.

Another possibility may be that insofar as iron ions are positively charged and acid cations are negatively charged, ion transfer due to charge attraction may occur to form the primary corrosion product. In Bondi and Penther (Some Electrical Properties of Collodial Suspensions in Oils, *Journal of Physical Chemistry,* January, 1953) conductance measurement techniques are illustrated for the measurement of the particle size of non-conducting solids (such as silica) in an all-oil system. Several explanations are offered for conductance in such a media but it is conceded that actual conductance is observed to be $10^2$ to $10^4$ greater than calculated values.

It is believed by the author that under some conditions corrosion may occur in the oil phase and that partial oil-wetting actually may cause increased corrosion. This is not entirely understood. However, in the normal oil well it is known that crude oils, because of their varied composition, have considerable water solubility or water dispersibility. Under dynamic conditions, where the particle sizes of oil and water droplets are small, ion transfer may be accomplished easily as the distance of travel is small. Also, corrodants such as $H_2S$ or $CO_2$ are soluble in both phases and therefore are readily available.

***Any discussions of this article not published above will appear in the June, 1956 Issue.***

A Review

# Inhibition of Metallic Corrosion in Aqueous Media*

By HARRY C. GATOS

HARRY C. GATOS was until recently with the Engineering Research Laboratory, Engineering Department, E. I. du Pont de Nemours and Co., Inc. He is now with the Lincoln Laboratory, Massachusetts Institute of Technology, Lexington, Mass. After doing his undergraduate work in chemistry at the University of Athens, Greece, he received an MA in chemistry from Indiana University and a PhD in inorganic chemistry from MIT. Prior to joining du Pont, Dr. Gatos served for a year as research associate in the department of metallurgy at MIT. His main research interests are in the fields of electrochemistry, metallic corrosion and chemistry of metal surfaces.

## Abstract

A brief discussion of corrosion processes from the electrochemical standpoint is given along with some of the electrochemical factors affecting corrosion. Organi and inorganic inhibitors are discussed separately and the mechanisms proposed for explaining their action as polarizers of the local corrosion cells are reviewed. Several experimental approaches to the study of corrosion inhibitors are given. In this connection a number of inhibitors are listed and their applications given.

## Introduction

METALLIC CORROSION undoubtedly has been a problem since common metals were first put to use. In the construction of lead covered decks for their ships[1] the ancient Greeks employed special copper nails coated with lead. Obviously they realized that metallic couples of common metals were undesirable in salt water. Protection of iron by coatings of bitumen, tar, etc., was known and practiced by the Romans.

It was not until the turn of the nineteenth century[2, 3] that some of the basic principles of corrosion were understood (this was soon after the discovery of the galvanic cell and Davy's theory on the close relationship between electricity and chemical changes[4].) During this period, Wollaston[5] proposed the electrochemical theory of corrosion, which basically is the theory accepted today. These advances served as the basis for Davy's[6] subsequent researches which led to the discovery of cathodic protection and effectively demonstrated the electrochemical nature of corrosion.

The electrochemical principles of corrosion were rediscovered in the early part of the twentieth century. At that time the rapid industrial growth and the high cost of losses resulting from metallic corrosion contributed greatly to the advancement of corrosion as a science.

The introduction of corrosion inhibitors for metallic protection can be traced back to the last half of the nineteenth century. Marangoni and Stephanelli[7] used extracts of glue, gelatin, and bran to inhibit the corrosion of iron in acids. This and subsequent discoveries of effective corrosion inhibitors were, to a large extent, the result of empirical studies. Even today, the trial and error process constitutes a common tool in the search for new inhibitors. Extensive basic studies on corrosion inhibitors and the factors governing their effectiveness have been in progress only for the past 30 years.

It is the purpose of this paper to discuss the major accomplishments made during those years in the field of corrosion inhibition in liquid media. Practical applications of specific inhibitors will be included only as illustrations for clarifying the present views on corrosion inhibition. Cathodic protection, protective coatings, and paints, although effectively employed for corrosion protection, will not be discussed. A brief account of the nature of metallic corrosion is considered essential before proceeding.

## The Electrochemical Nature of Corrosion

In the last 150 years it has been established beyond doubt that metallic corrosion in electrically conducting liquid media is of an electrochemical nature. Corrosion of metals, particularly in acids, usually is accelerated by the presence of impurities through the formation of local electrolytic cells. The impurities serve as cathodes of these cells; the metal serves as anode and consequently suffers electrolytic dissolution. Corrosion of zinc in sulfuric acid is an example of such dissolution. In 0.5N $H_2SO_4$ the corrosion rate of pure zinc[8] increases by a factor of about 2 if pure zinc is alloyed with 1.1 percent arsenic. If pure zinc is alloyed with 0.97 percent copper, its corrosion rate increases by a factor of about 200.

Two dissimilar metals in electrical contact and immersed in a conducting solution also form an electrolytic cell. The less noble of the two metals becomes the anode and corrodes whereas the other metal becomes the cathode and therefore is protected. Iron, for example, is protected by magnesium in sodium chloride solutions.

Impurities or metallic couples, however, are not essential in order for metallic corrosion to take place under electrochemical action. When a single metal or alloy corrodes, local electrolytic cells generally operate on its surface. Some parts of the metallic surface serve as anodes, and others as cathodes. The distribution of the anodic and cathodic areas depends upon such factors as the energetics of the various parts of the surface (crystal-lattice imperfections, strains, etc.), the distribution of surface contaminants (layers of adsorbed substances or insoluble metal compounds), and the environmental conditions (access

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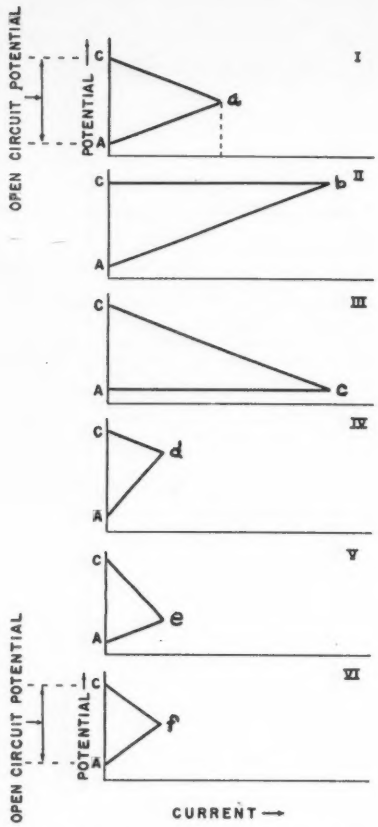



Figure 1—Polarization curves of corrosion local cells.

of the corrosive medium, air, or other gases to the various parts of the surface). The quantity of electricity flowing through the local cells is equivalent to the amount of metallic corrosion in accordance with Faraday's law*. [9, 10]

As electrical current begins to flow through a local cell, the potential of the anode and the potential of the cathode (A and C, respectively, in Figure 1, I) shift closer to each other, i.e., become polarized. The anodic potential shifts toward more cathodic values, and the cathodic toward more anodic values. It is believed that "polarization results from the slowness of one or more of the processes occurring at the electrode during the discharge of an ion."[11] At "a," the potential of the anode and cathode approach each other. The current at "a" represents the maximum current which can flow without altering the experimental conditions at hand, and corresponds to a maximum steady-state corrosion theoretically possible. The potentials of the anodes and cathodes do not become quite identical because of the fact that there is usually an IR-drop due to the corrosive medium or the presence of metal compounds on the metal surfaces. Figure 1

It is apparent that conditions which decrease the slopes of the polarization curves, i.e., shift the convergence point of anodic and cathodic potential to higher current values, will result in acceleration of corrosion; shifting to lower current values will result in inhibition of corrosion. Thus, by preventing polarization of the cathode, the convergence of the two potentials will occur at "b" (Figure 1, II), and by preventing the polarization of the anode the convergence will occur at "c" (Figure 1, III). Both "b" and "c" correspond to higher current values than "a", and for that reason there is increased corrosion.

On the other hand, the steady-state corrosion current—and therefore corrosion—decreases by increasing polarization of the anode ("d", Figure 1, IV) or the cathode ("e", Figure 1, V) or both ("f", Figure 1, VI).

### Inhibition by Anodic Polarization

As pointed out above, corrosion of metals in aqueous media takes place through dissolution of metal at the anodic areas. Thus the main anodic reaction for a corroding metal can be represented as:

$$M \rightarrow M^{+x} + xe^-$$

where M is the corroding metal, $M^{+x}$ the metal ions formed during corrosion, and x the oxidation number of the ions.

The electrons released at the anodes are transferred to the cathodes through metallic conduction and are consumed there by cations present in the solution. In this way, a current flow through the cell is realized. Corrosion inhibitors retarding the anodic reaction cause anodic polarization. Referring to Figure 1, IV, the anodic curve becomes Ad. (It is assumed that the cathodic polarization is not affected.) The current corresponding to "d" is less than that corresponding to "a", and, therefore, corrosion is decreased. Corrosion would be stifled completely if the potential of the anodes reached that of the cathodes at infinitesimally small currents.

In general, with increasing anodic polarization, the over-all corrosion of a metal diminishes. Speaking in terms of corrosion inhibitors, it is apparent that their inhibiting effectiveness increases with their ability to induce anodic polarization at relatively low current values. Inhibitors inducing anodic polarization are classified by Evans[12] as *anodic inhibitors.*

If the corrosion current is proportional to the anodic areas, i.e., controlled by the anodic reaction (anodic control), it is obvious that the decrease in over-all corrosion should be proportional to the portion of the anodic areas being polarized. On the other hand, if corrosion is controlled by the cathodic reactions (cathodic control), the corrosion current, and therefore the total amount of corrosion is not affected by decreasing the anodic areas. In this case the same amount of corrosion must be distributed over a smaller anodic area, resulting in intensified localized attack (pitting).

Inasmuch as the majority of the common corrosion systems are cathodically controlled, it is apparent that anodic inhibitors must be employed in sufficient

* The corrosion of metals in non-electrolytes cannot generally be explained on the basis of the electrochemical mechanism. This type of corrosion has not been investigated extensively, perhaps because it is less common and less important than aqueous corrosion.

amounts to ensure complete inhibition and to prevent pitting. It is for this reason that anodic inhibitors often are classified as dangerous inhibitors.[12]

A number of substances are known to be anodic inhibitors, such as the alkali metal salts of chromates, phosphates, carbonates, silicates, etc. The mechanism by which they retard the anodic reactions and thus act as anodic polarizers will be discussed later.

Some of these inhibitors, in addition to causing localized attack, may accelerate the over-all corrosion if used in small concentrations.[13] It has been reported that sodium chromate[14] and potassium permanganate,[15] when present in small quantities, accelerate the corrosion of aluminum in sodium hydroxide solutions, whereas at higher concentrations they are effective inhibitors for the same corrosion systems. It is likely that in these cases the inhibitors act as cathodic depolarizers when present in small concentrations and as anodic polarizers at higher concentrations.

### Inhibition by Cathodic Polarization

The main anodic reaction in metallic corrosion consists of the oxidation of the metal to its ions. The cathodic reaction consists of the reduction of ions. The type of reduction depends upon the corrosion environment. Thus, during the corrosion of some common metals (Zn, Fe) in acids ($H_2SO_4$, HCl), the main cathodic reaction consists of the reduction of hydrogen ions:

$$2\,H^+ + 2\,e^- \rightarrow H_2$$

In neutral solutions containing oxygen, the main cathodic reaction is the reduction of oxygen to hydroxyl ions:

$$\tfrac{1}{2}\,O_2 + H_2O + 2\,e^- \rightarrow 2\,OH^-$$

If the corrosion environment is right, a number of substances other than $H^+$ and $O_2$ can be reduced at the local cathodes during metallic corrosion.

Inhibitors interfering with the above reactions cause cathodic polarization; i.e., shift the potential of the cathodes toward that of the anodes so that the anodic and cathodic potentials converge at smaller current values ("e", Figure 1, V) than they would in the absence of inhibitors ("a").

The cathodic areas are not attacked during corrosion, since the metal itself does not participate chemically in the cathodic reactions. Consequently, cathodic inhibitors, with a few exceptions,[16] do not lead to intensified or localized attack. If corrosion is controlled by cathodic reactions, decrease in the cathodic area due to partial inhibition will result in an over-all decrease in corrosion. If on the other hand the corrosion is controlled by anodic reactions, a decrease of the cathodic area will increase the cathode current density, but will have no effect on the over-all corrosion or its nature. While an increase in cathode current density may cause the reduction of substances present which would not otherwise be reduced, such reductions are usually without significant consequence.

Arsenic salts which are effective in inhibiting corrosion of steel in inorganic acids and magnesium or nickel salts which inhibit corrosion of steel in neutral water systems belong in the class of cathodic inhibitors. Because they exhibit no adverse effects on corroding systems, even if employed in amounts insufficient to ensure sufficient inhibition, they usually are referred to as safe inhibitors.[12]

### Inhibition by Mixed Polarization

A number of substances inhibit metallic corrosion by interfering with both anodic and cathodic reactions, thus simultaneously causing anodic and cathodic polarization. This type of inhibition is represented in Figure 1, VI, by the polarization curves "Af" and "Cf". Gelatine, glue, and other high-molecular-weight substances fall into this category and are commonly classified as general inhibitors. It is believed that they concentrate at the metal-liquid interface. Because of their high viscosity they cause a decrease in the diffusion rates of the corrosive substances toward the metal surface, and thus, provide a shield for the metal.

In classifying the corrosion inhibitors into anodic, cathodic, and general inhibitors, it is assumed that anodic inhibitors do not interfere with cathodic reactions, nor do cathodic inhibitors interfere with anodic reactions. Although such an assumption is often valid, it should be kept in mind that many anodic inhibitors, to some extent, cause cathodic polarization; also that cathodic inhibitors cause some anodic polarization. Such inhibitors are still considered as anodic or cathodic depending upon the electrode at which their action is more pronounced.

In addition to causing anodic, cathodic, or mixed polarization, as discussed above, corrosion inhibitors also may alter the open circuit potential which could lead to decreased corrosion.

### Experimental Studies of Polarization Phenomena in Corrosion Inhibition

By measuring directly and unambiguously the open circuit potential of the local cells (See Figure 1) operating on corroding metals and the potential of the local anodes and cathodes as a function of corrosion current in the presence and absence of inhibitors, one should obtain very basic and significant information about the processes associated with corrosion inhibition. Such direct measurements are hardly possible, due primarily to the small size of the local cells, their random distribution over the metal surface, and the fact that during the course of corrosion anodic sites may become cathodic and vice versa. Indirect methods of considerable interest have been proposed for achieving the above information, but they are rather complex and have substantial limitations.[10, 17, 18, 19] They will not be included in this discussion.

It is possible, however, to study the action of corrosion inhibitors on the polarization characteristics of corroding metals by more or less indirect methods. Two such methods based on potential measurements and application of external emf on corroding metals are used quite frequently and will be discussed here.

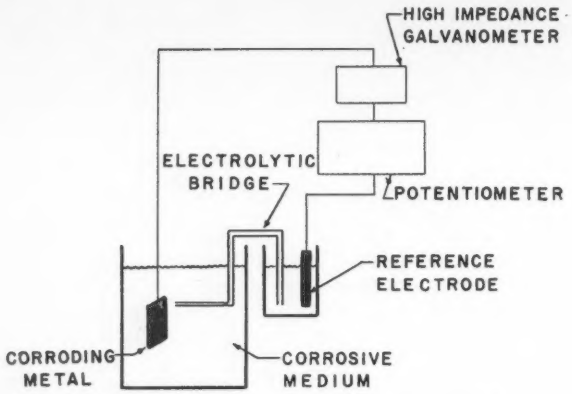



Figure 2—Apparatus for measuring corrosion potentials.

*Potential Measurements*

Electrode-potential measurements of metals in aqueous solutions have been used very widely in studying corrosion and corrosion inhibition. They consist of measuring the potential of the corroding metal against a reference electrode, usually a saturated calomel or a silver-silver chloride electrode.[20] Figure 2 illustrates schematically the experimental arrangement commonly used for such measurements.

There is considerable confusion in regard to the sign conventions and nomenclature of electrode potentials. In this discussion the convention adopted by The Electrochemical Society and other professional societies in this country and Europe will be used. It is usually called the "European Convention," in contrast to the "American Convention" used by the American Chemical Society.

According to the European Convention,[21] a metal more noble than the standard hydrogen electrode (SHE) has a positive (+) potential and is the positive terminal of a cell consisting of the SHE and the metal. Similarly, it has a negative (—) potential if it is less noble than the SHE. The sign of the electrode potential against the SHE corresponds to the polarity as determined by any DC potentiometer. Metal "A" has a more positive potential or is more cathodic than metal "B" if it is more noble than metal "B"; i.e., it serves as the cathode (noncorroding electrode) when coupled with "B", which serves as the anode (corroding electrode). The signs are reversed in the American Convention.

The electrode potential of a metal, obtained by means of an arrangement similar to that shown in Figure 2, represents approximately the average potential of the local cells.[22] It generally fluctuates erratically with time and eventually reaches a more or less steady value. This steady value corresponds to the average of the convergence points of the potential of local anodes and cathodes ("a", Figure 1, I) and is indicative of steady-state corrosion.

At this point it should be emphasized that the potential of corroding metals is not necessarily related to the oxidation potential of the metals appearing in the electromotive force series. The former is the result of anodic and cathodic polarization phenomena, which oppose the direction of the current flow in the local cells and are highly irreversible;[22] the latter is the result of a single reversible electrode process (the oxidation of the metal to its ions) under very carefully controlled experimental conditions. Therefore, the emf series quite ofter cannot serve as a guide for predicting the corrosion behavior of corroding metals in various liquid media,[18] especially in the case of the common metals.

Electrode potential measurements have been employed very widely for inhibitor studies, and on many occasions they have contributed greatly to the gaining of an understanding of corroding systems.[22] The limitations of such measurements, however, must be considered carefully. The potential of a metal is frequently in itself of little importance. The changes it undergoes in the presence of inhibitors or varying concentrations, however, are usually of significance.

Furthermore, shifting of the potential to more noble or more active values cannot serve as a dependable criterion of increasing or decreasing corrosion rates.[23, 24] As shown in Figure 1, shifting of the potential to more anodic values may lead to either higher or lower corrosion rates, depending upon whether the shift corresponds to higher or lower corrosion current. The same is true where the potential is shifting to more cathodic values.

On the other hand, corrosion inhibition may take place even without any shift of the electrode potential of the metal (See Figure 1, VI). Thus, potential measurements should, in general, be considered in conjunction with the corrosion rates and the chemistry and geometry of the system at hand. Furthermore, the factors, other than the presence of inhibitors, which affect the potentials (temperature, stirring, etc.) should be carefully controlled.[25]

**Shifting of Potential.** As pointed out earlier, shifting of the potential to more cathodic values is indicative of anodic polarization if accompanied by a decrease of the corrosion rate. Thus, the action of many inhibitors at the anodic areas (anodic inhibitors) has been shown by means of potential measurements. In the presence of a number of inhibitors ($Na_2SiO_3$, $Na_2CO_3$, NaOH, $Na_2HPO_4$, $NaH_2PO_4$, $Na_3PO_4$) inhibiting the corrosion of steel in aerated neutral or alkaline water systems, the potential of steel ranges from 0 to 0.35v. (standard hydrogen scale).[26] However in deaerated solutions containing the same substances, where no inhibition takes place the potential of steel is less cathodic by several tenths of a volt. In the case of $Na_2CrO_4$ and $NaNO_2$, which are effective in both aerated and deaerated solutions, the potential of steel does not change in going from deaerated to aerated solutions. However, it is more cathodic in the presence of these inhibitors than it is in their absence.

The potential of steel in sulfuric acid solution also is shifted toward more cathodic values in the presence of amines and other nitrogen-containing organic inhibitors[27] (See Table 1). On this basis these inhibitors also are believed to be predominantly anodic polarizers.

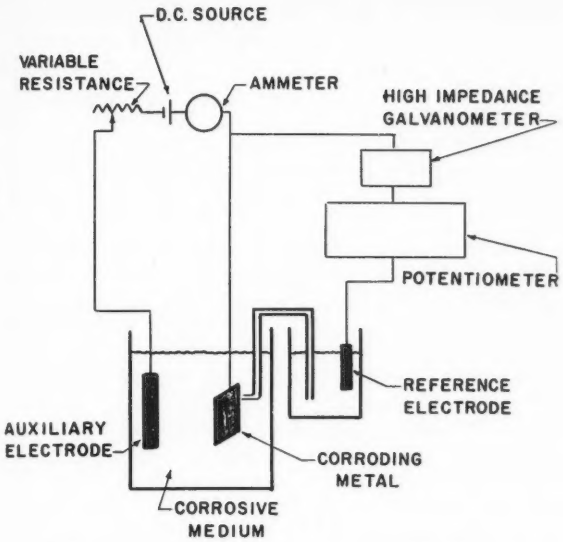



Figure 3—Apparatus for polarization studies with externally applied emf.

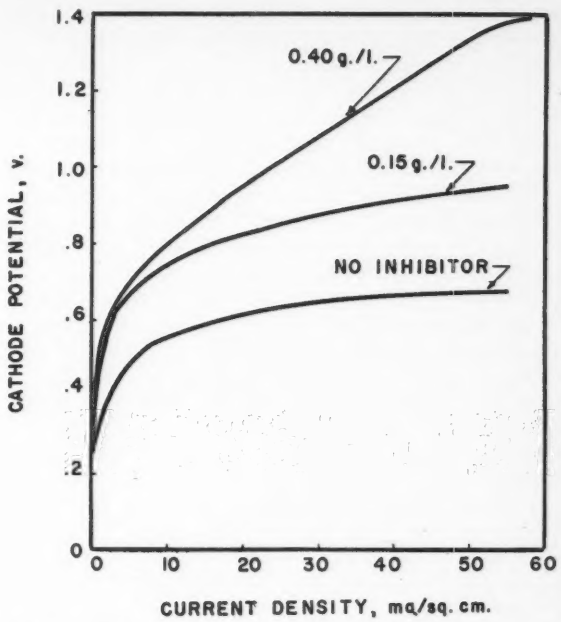



Figure 4—Effect of quinoline ethiodide on the cathodic polarization of Armco iron in 1N $H_2SO_4$.

On the other hand, salts of trivalent arsenic, which are very effective in inhibiting the corrosion of steel in sulfuric acid solutions, shift the potential of steel to more anodic values indicative of cathodic polarization.

Electrode potential changes of metals in aqueous media have been further employed as a measure of the extent and type of adsorption of inhibitors on metal surfaces. Thus, in the case of mild steel in 1N $H_2SO_4$ inhibited by amines (such as triethylamine[28]), it was found that common gas-adsorption isotherms are obtained by plotting the change in potential versus inhibitor concentration.

Similar results were obtained for stainless steel and titanium inhibited[29] by $CrO^{=}_4$, $Cu^{++}$, and $Fe^{+++}$. These results were used as supplementary evidence that inhibitors adsorb on metals in amounts of the order of a monomolecular layer. Through the same studies it was shown also that a portion of the adsorbed inhibitor could be removed by washing with water.

*Polarization Studies with Externally Applied EMF*

The electrode potentials of corroding metals represent the average potential of the local cells (convergence points of local anode and cathodes). They are indicative of the polarization behavior of the anodes independently of that of the cathodes, and vice versa, but only in a qualitative way. For this reason and because direct measurements of the polarization of the anodes and cathodes are virtually impossible, the anodic and cathodic behavior of corroding metals has been studied in numerous cases by making the metals anodic or cathodic against an auxiliary electrode in the corrosive medium by means of externally applied emf. In this way the entire metal may be made the anode or cathode of an electrolytic cell.

The current density of the metal under study usually ranges from 1 to 100 ma/sq cm, presumably approximating the values encountered during corrosion. The potential of the metal—under the external emf—is measured against a reference electrode. Plots of this potential versus the current density represent polarization characteristics of the metal in the desired environment. Figure 3 represents a typical experimental arrangement for polarization studies with externally applied emf.

**Quinoline Ethiodide.** By employing the above technique, Chappel, Roetheli, and McCarthy[30] studied the action of quinoline ethiodide (a representative

**TABLE 1—Weight Loss and Corrosion Potential of Mild Steel in 10 Percent Sulfuric Acid with Various Inhibitors.[27]**

| INHIBITOR | Concentration of Inhibitor M | Weight Loss mg./25.0 $cm^2$ | Mean Corrosion Potential mv. vs. Hydrogen in Same Acid |
|---|---|---|---|
| None | ..... | 956 | —235 |
| Aniline | 0.0063 | 943 | —233 |
| Phenyl-β-naphthylamine | Sat'd. | 938 | —234 |
| p-Phenylenediamine | 0.0063 | 886 | —225 |
| Pyridine | 0.0063 | 862 | —232 |
| Diethylaniline | 0.0063 | 513 | —209 |
| Acridine | Sat'd. | 404 | —227 |
| Quinoline | 0.0063 | 370 | —201 |
| Proflavine | Sat'd. | 331 | —197 |
| 2-4-Dimethylquinoline | 0.0063 | 321 | —192 |
| 2-6-Dimethylquinoline | 0.0063 | 178 | —192 |
| Enflavine | Sat'd. | 125 | —195 |
| Acriflavine | Sat'd. | 112 | —196 |
| α-Naphthoquinoline | 0.0063 | 78 | —177 |
| β-Naphthoquinoline | 0.0063 | 73 | —178 |
| Ethylquinolinium bromide | 0.0063 | 63 | —184 |

Temperature 25 C., Corrosion Time 24.25 hours.

inhibitor for pickling of metals in $H_2SO_4$). They found that the potential of mild steel, Armco iron, and zinc, serving as anodes, decreased only to a small extent (a few hundredths of a volt) by the addition of varying amounts of inhibitor. This decrease was considered too small to account for the decrease of corrosion in the presence of this inhibitor.

On the other hand, by employing the above materials and other metals as cathodes in the same electrolytic cell, the above mentioned authors observed very pronounced cathodic polarization. (Figure 4 represents typical cathode polarization curves.) They also found that the hydrogen overvoltage increased considerably with increasing inhibitor concentration. On this basis, it was concluded that pickling organic inhibitors interfere with the cathodic reaction. This work was confirmed and extended to a number of other inhibitors by Jimeno, Grifoll, and Morral.[31]

Through similar studies it was generally found that nitrogen-containing organic compounds[32] (amines, anilines, pyridines, etc.) which inhibit the corrosion of steel in $H_2SO_4$, were cathodic, rather than anodic, polarizers.

**Corrosion Accelerators.** Bockris and Conway[33] investigated the effect of a group of organic inhibitors (primarily nitrogen-containing compounds) on the overvoltage of iron in 0.1N HCl. At the same time they studied the effect of corrosion accelerators (nitrobenzene). They established that at high current densities (up to 0.1 amp/sq cm) the hydrogen overvoltage increases with increasing inhibitor concentration. Furthermore, they found that the extent of corrosion inhibition and the increase in hydrogen overvoltage run approximately parallel to each other. Corrosion accelerators on the other hand, decrease the hydrogen overvoltage. Other investigators also have arrived at similar conclusions.[34, 35]

The foregoing conclusions have been at least partially questioned[27, 35, 36] on the basis that the experimental conditions under which the polarization studies were conducted do not necessarily resemble those existing during corrosion. The externally applied current densities probably exceed by far the ones encountered during corrosion. Furthermore, electrode potential of metals in acids (without externally applied emf) containing organic inhibitors is shifted toward more cathodic values and is indicative of anodic polarization under normal conditions, although simultaneous cathodic polarization cannot be excluded.

In spite of the existing controversy as to the specific action of some of the corrosion inhibitors, the above and other studies have shown conclusively that inhibitors, in general, inhibit corrosion by inducing anodic, cathodic, or mixed polarization of the local cells whose operation is responsible for corrosion.

## Mechanisms of Inhibitor Action

### *Classification of Inhibitors*

In discussing the mechanisms of inhibitor action, it is advantageous to classify the inhibitors into various types. A number of criteria are used for this purpose. On the basis of their chemical nature, inhibitors are divided into inorganic (e.g., sodium dichromate) and organic (e.g., tetramethylene diamine, gelatin) categories. According to the nature of their polarizing action, they are classified as anodic (e.g., phosphates), cathodic (arsenic salts), and general (gelatin); or as surface-conversion inhibitors (phosphates, arsenic salts), adsorption inhibitors (amines), and diffusion inhibitors (gelatin). They are divided into brine inhibitors (sodium dichromate), pickling inhibitors (amines), water inhibitors (phosphates), antifreeze inhibitors (sodium tetraborate), etc., depending on the corrosive medium in which they are employed.

It should be pointed out that there is a great deal of overlapping among the various types of inhibitors. For that reason particular importance should be assigned to these classifications other than to recognize that they constitute convenient tools for studies of a general nature.

In the present discussion, corrosion inhibitors are divided into two main classes, inorganic and organic. The action of the former has been the subject of extensive controversy. On the action of the latter, there is more or less general agreement.

### *Inorganic Inhibitors*

**Anodic Inhibitors:** As pointed out above, inhibitors retarding or arresting the anodic reactions of a corroding metal are classified as anodic inhibitors. Some typical inorganic anodic inhibitors and the

**TABLE 2—Typical Inorganic Anodic Inhibitors and Corrosion Systems in Which They Are Effective.**

| Inhibitor | Approximate Inhibitor Conc., % | Corrosion Environment | Metallic System |
|---|---|---|---|
| Borax[71] ($Na_2B_4O_7$) | 2—3 | Alcohol antifreeze mixtures | Automobile cooling systems |
| Calgon[72] (glassy phosphates) | Small Amount | Water systems | Steel |
| Disodium hydrogen phosphate[73] ($Na_2HPO_4$) | 0.5 | Citric acid | Steel |
| Potassium dichromate[74] ($K_2Cr_2O_7$) | 0.05-0.2 | Tap water 20—90 C. | Iron—brass |
| Potassium dihydrogen phosphate ($KH_2PO_4$) + sodium nitrite[75] ($NaNO_3$) | Small Amount +5% | Sea Water | Steel |
| Potassium permanganate[15] ($KMnO_4$) | 0.10 | 0.30 N NaOH solution | Aluminum |
| Sodium benzoate[76] ($C_6H_5COONa$) | 0.5 | 0.03% NaCl solution | Mild steel |
| Sodium carbonate[77] ($Na_2CO_3$) | Small Amount | Gas condensate wells | Iron |
| Sodium chromate[78] ($Na_2CrO_4$) | > 0.5 | Cooling water | Electrical rectifier systems |
| Sodium chromate[79] ($Na_2CrO_4$) | 0.07 | $CaCl_2$ brine | Cu, brass |
| Sodium dichromate[80] ($Na_2Cr_2O_7$) | 0.025 | Air-conditioning water | Air-conditioning equipment |
| Sodium dichromate ($Na_2Cr_2O_7$) + sodium nitrate[81] ($NaNO_3$) | 0.1 + 0.05 | Water | Heat-exchange devices |
| Sodium hexametaphosphate[82] ($NaPO_3)_6$ | 0.002 | Water around pH 6 | Lead |
| Sodium metaphosphate[83] ($NaPO_3$) | Small Amount | Ammonia | Mild steel condensers |
| Sodium nitrite[22] ($NaNO_2$) | 0.005 | Water | Mild steel |
| Sodium nitrite[84] ($NaNO_2$) | 20% of sea water | Sea water/distilled water mixtures | Mild Steel |
| Sodium orthophosphate[39] ($Na_3PO_4$) | 1 | Water pH 7.25 | Iron |
| Sodium silicate[85] ($Na_2SiO_3$) | Small Amount | Sea water | Zn, Zn-Al alloys |
| Sodium silicate[86] ($Na_2SiO_3$) | 0.01 | Oil-field brines | Steel pipes |

corrosion systems in which they are effective are listed in Table 2.

The mechanism of the action of the inorganic anodic inhibitors which results in polarization of the local cells and therefore corrosion inhibition has been the subject of considerable study and long controversy. Two main points of view have been advanced, one supporting formation of protective insoluble films on metals in the presence of the inhibitors, and the other, adsorption or chemisorption of the inhibitors on the metal surfaces.

*(a) Protective Film Mechanism:* According to Evans,[12] most sodium or potassium salts containing anions which form a sparingly soluble salt with the metal under consideration act as anodic inhibitors. In the case of sodium phosphate, for example, the phosphate ions in neutral or alkaline solutions form insoluble iron phosphate at the anodes, where iron ions enter the solution. In the case of the chromates, Hoar and Evans[37] proposed that they react with ferrous ions and precipitate an adherent protective film of hydrated ferric and chromic oxides on the anodic areas.

More recent studies on inhibition with sodium hydroxide,[38] orthophosphate,[39] nitrite,[40, 41] chromate,[42] and other anodic inhibitors[26] (sodium carbonate, acetate, benzoate, and molybdate) in aerated solutions showed the formation of an invisible protective thin film of $\gamma$—$Fe_2O_3$.

In the absence of dissolved air, however, inhibition was afforded only by inhibitors with oxidizing anions[26] (sodium nitrite, chromate, and to some extent sodium molybdate and tungstate), and not by those inhibitors which do not contain oxidizing anions. Pryor and Cohen[26] concluded that the protective action of anodic inhibitors is based on the formation of protective films of $\gamma$—$Fe_2O_3$ maintained in constant repair.

In the case of inhibitors with non-oxidizing anions, the films are formed entirely by dissolved oxygen. These inhibitors do not participate directly in the formation of the protective films. They merely contribute to repairing discontinuities in the oxide films, as shown by the occurrence of film inclusions containing some of the insoluble salts of the inhibitors. The formation of the films is believed to take place through adsorption of oxygen, followed by relatively slow chemical reaction with the metal. These films reach an equilibrium thickness of about 200 Å.

In the case of inhibitors with oxidizing anions (nitrites and chromates) the protective film in aerated solutions again is formed primarily by dissolved oxygen. In deaerated solutions, however, the inhibitors, due to their oxidizing character, react directly with iron to form protective oxide films. Molybdates and tungstates are much milder oxidizing agents than chromates and, therefore, do not inhibit corrosion effectively in the absence of dissolved air.

*(b) Adsorption Mechanism*: The view that the formation of protective films consisting of stoichiometric chemical compounds is a necessary prerequisite for inhibition has been disputed by a group of investigators. According to Uhlig,[29, 43] formation of an oxide film is not necessary for inhibition, although such a film may form and contribute to the over-all protection. Inhibition by chromates and other oxidizing inhibitors is primarily due to physical and activated adsorption—chemisorption—through which the valence forces of the surface metal atoms are satisfied.

Chemisorption, in contrast to physical adsorption, is associated with high activation energy and leads to the formation of surface (stoichiometric) compounds, with the surface metal atoms remaining in their respective metal lattices. The portion of the chromates held on the metal surface by physical adsorption can be removed easily by washing with water or other solvents (reversible adsorption), in contrast to the portion held on the surface by chemisorption.

These views were supported by potential-measurements studies[29] of iron in chromate solutions. By washing the iron samples with distilled water, after they were immersed in the chromate solution, it was found that about half of the effect of chromates on the potential of iron was eliminated. Shifting of the electrode potential toward more cathodic values, indicative of anodic polarization, was taken as a measure of the extent of chromate adsorption. Iron samples immersed in radioactive chromate solution and subsequently washed extensively with distilled water still showed residual activity.[44, 45, 46]

In studying the behavior of iron in concentrated nitric acid,[47] it was found that immersing of iron in chromate solutions, prior to immersing in nitric acid, caused less iron to dissolve in nitric acid before dissolution of iron was arrested. This effect was partially eliminated by washing the iron with water after immersion in chromates.

Molybdates and tungstates, chemically analogous to chromates but with considerably less oxidizing power, were found to behave as inhibitors similar to the chromates.[48] Their action also was attributed to adsorption.

In studying passivity of steel and chromium in chromate solutions by means of radiotracer techniques and contact potentials, Hackerman[45, 49] found that oxide films were formed on the metal surface. He concluded, however, that anions adsorbed at the oxide-solution interface were responsible for passivity, rather than the metal oxide film.

The above controversy between the proponents of protective-film and adsorption theories might be attributed to a number of factors: (1) Metallic corrosion and corrosion inhibition are highly complicated processes controlled by numerous factors. Some of these factors are as yet exceedingly difficult to define. As a result, direct comprehensive studies present formidable problems. Furthermore, due to their extreme thinness and intricate structure, the metal-liquid interfaces, which are the stage of the above processes, are beyond the sensitivity of conventional experimental techniques. (2) The processes involved in inhibition may vary considerably from one system to the other so that generalized studies either are vir-

tually impossible or suffer from serious limitations. (3) It is not impossible that either or both of the main mechanisms proposed may be operating, depending upon the corrosion system and the experimental conditions.

**Cathodic Inhibitors:** The most common cathodic reactions in metallic corrosion are the reduction of free oxygen to hydroxyl ions (neutral or alkaline solutions) and the reduction of hydrogen ions to free hydrogen (acid solutions). Inhibitors slowing down or arresting the above reactions are classified as cathodic inhibitors.

Salts of zinc, nickel, manganese, and chromium are such inhibitors for iron in neutral solutions. Their action is believed to be due to their ability to form insoluble hydroxides which are protective by adhering at the cathodic areas, where hydroxyl ions are formed.[16, 50, 51] These hydroxide films vary in thickness and appearance and quite often exhibit discontinuities allowing corrosion to proceed slowly. For reasons explained earlier cathodic inhibitors, in contrast to anodic inhibitors, usually do not lead to intensified attack, even if used in insufficient quantities. Cases of intensified attack caused by cathodic inhibitors are the exception rather than the rule.[16]

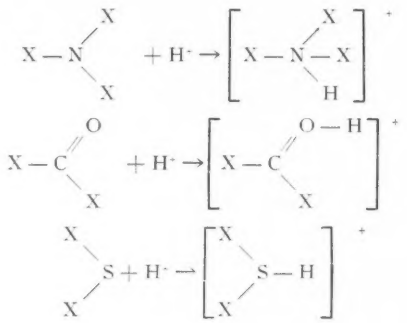
Salts of arsenic, antimony, and mercury[52] act as cathodic inhibitors in acid solutions. Thus antimony salts inhibit acid attack on iron[53] and trivalent arsenic compounds inhibit the corrosion of carbon steel in dilute[54] as well as in hot (up to 85 C.) concentrated (50 to 72 percent) sulfuric acid.[55] It is generally believed that metallic antimony and arsenic, respectively, are deposited on the cathodic areas and decrease the hydrogen evolution by causing a considerable increase of the hydrogen overpotential.

*Organic Inhibitors*

Organic inhibitors in general do not undergo chemical changes during inhibition; inorganic inhibitors do so in many cases. It is perhaps for this reason that the mechanism of the action of organic inhibitors has been the subject of much less controversy than that of the inorganic inhibitors.

**Polar Organic Inhibitors:** Numerous low-molecular-weight organic compounds with polar molecules, containing elements of the fifth and sixth groups of the periodic table, are in commercial use or have been proposed as corrosion inhibitors. Of these, compounds containing nitrogen (amines, pyridines, quinolines, etc.) oxygen (aldehydes, ketones, etc.) and sulfur (mercaptans, etc.) are the most common. Some typical polar organic inhibitors and the corrosion systems in which they are employed are shown in Table 3.

Chappell, Roetheli and McCarthy,[30] in studying the action of quinoline ethiodide, concluded that the action of organic inhibitors is confined almost entirely to the cathode reactions. Systematic studies on numerous polar organic inhibitors were first undertaken by Mann and his co-workers.[32, 56, 57, 58] These studies were conducted in acid solutions and included compounds containing nitrogen, oxygen, and sulfur. These compounds in acid solutions have a tendency to form ions of the ammonium, oxonium, or sulfonium type as shown below:



In the above cases X stands for organic radicals or hydrogen atoms. Mann and his co-workers proposed that in this ionic form the inhibitors are attracted and therefore adsorb at the cathodic areas. Since these inhibitors cannot be electrically discharged under experimental conditions, they remain adsorbed and prevent hydrogen ions from discharging at the cathodes, thus inhibiting corrosion by cathodic polarization. The above studies revealed that inhibition by members of homologous series increases with chain length and the cross-sectional area of the molecule. Mann's conclusions were supported by the results of other investigators[31, 34, 59, 60] who also found by applying external emf that low-molecular-weight organic inhibitors are cathodic polarizers.

Bockris and Conway[33] also attributed the action of the above inhibition to cathodic phenomena. They felt it was due, however, to an increase of the hydrogen overvoltage rather than to protection by an adsorbed film.

The theory based on cathodic adsorption of inhibitors containing elements of the fifth and sixth groups of the periodic table recently has been questioned. Hoar[27, 36] has observed a shift of the electrode potential of corroding

**TABLE 3—Typical Organic Inhibitors and the Corrosion Systems in Which They Are Effective.**

| Inhibitor | Approximate Inhibitor Conc., % | Corrosion Environment | Metallic System |
|---|---|---|---|
| Benzanilide[87] | 0.2 | Lubricants | Cd-Ni, Cu-Pb bearings |
| Formaldehyde[88] | Small Amount | Oil wells | Oil-well equipment |
| Formaldehyde[89] | 0.05 | Sour crude oil | Diesel engines |
| Dioctyl ester of sulfosuccinic acid[90] | 0.05 | Refined petroleum oils | Pipe lines |
| Erythritol[91] | Small Amount | $K_2SO_4$ solution | Mild steel |
| Ethylaniline[92] | 0.5 | HCl solutions | Ferrous metals |
| Mercaptobenzothiazole[93] | <1 | HCl solutions | Iron and steel |
| Morpholine[94] | 0.2 | Water | Heat-exchange systems |
| Oleic acid[95] | Small Amount | Polyhydric alcohols | Iron |
| Phenyl acridine[96] | 0.5 | $H_2SO_4$ solutions | Iron |
| Pyridine + phenylhydrazine[97] | 0.5 + 0.5 | HCl solutions | Ferrous metals |
| Quinoline ethiodide[30] | 0.1 | 1 N $H_2SO_4$ | Steel |
| Rosin amine-ethylene oxide[98] | 0.2 | HCl solutions | Mild steel |
| Tetramethylammonium azide[99] | 0.5 | Aqueous solutions of organic solvents | Iron and steel |
| Thiourea[100] | 1 | Acids | Iron and steel |

metals in the presence of the above organic inhibitors toward more cathodic values, a situation indicative of anodic polarization. By applying relatively small external current densities, Cavallaro and Bolognesi[61] found both anodic and cathodic polarization with these inhibitors. Similar results are reported by Hackerman and Sudbury.[28]

On the basis of these and other investigations, Hoar and Hackerman concluded that general adsorption rather than specific adsorption takes place in metal surfaces. According to Hackerman and Makrides,[35] this adsorption is not decisively controlled by the existence of local cells. During adsorption studies with inhibitors in benzene solutions, it was found that both physical adsorption and chemisorption take place.[62] In the bond resulting from chemisorption a pair of the inhibitor's electrons is shared with the metal.

The views of general adsorption also are favored by Gatos[63] who found that numerous organic inhibitors adsorb on mercury over a wide range of potentials, although preferential adsorption at cathodic or anodic potentials takes place in some instances.

**High-Molecular-Weight Organic Inhibitors:** Gelatin, egg albumin, dextrine, agar, and other high-molecular-weight organic substances of plant and animal origin have been employed as corrosion inhibitors in acid as well as in neutral media. Their action is believed to be due to their concentration or coagulation at the metal-liquid interface, providing a shield to the metal surface.

Machu[64, 65] attributes their action to the formation of a porous layer, which causes an increase in the electrical resistance of the surface layer. He found a direct relationship between surface layer resistance and corrosion inhibition.

## Selection and Study of Inhibitors for Unknown Systems

In approaching the solution of any practical corrosion problem by means of inhibitors a literature search for reports on the use of inhibitors on identical or similar systems is usually the first step. Any information obtained in this way should be used with great caution for, as pointed out above, in many cases effective inhibitors if improperly used may accelerate corrosion or cause intensified attack. Thus, laboratory or pilot plant type tests should be performed, even in the case of known systems, in order to confirm the inhibitor concentration ranges and eliminate the possibility that unidentified factors will not offset the inhibiting action in the system at hand. This is especially important in the case of anodic inhibitors.

Actual corrosion inhibition tests are of even greater importance for studying the inhibiting properties of previously unexplored substances or for determining the effectiveness of known inhibitors in new corrosion systems. In such cases it is essential that the character of the uninhibited corrosion be investigated by means of corrosion rate measurements, and by macro- and microscopic examination of the corroded surfaces. The testing conditions on the laboratory-scale experiments should resemble those of the plant process as much as possible.

Some of the factors to be considered are (1) solution composition—actual plant process solutions should be used if possible, (2) temperature variations, (3) flow conditions, (4) ratio of specimen surface area to volume of solution, (5) testing time, and (6) concentration of oxygen and other gases. The specimen under test should be examined periodically, especially for evidence of pitting corrosion. Numerous laboratory tests simulating field conditions have been proposed for evaluating corrosion inhibitors. Recently, for example, an apparatus was proposed for simulating field conditions of steam condensate systems[66] and another one for field conditions of oil wells*.[67, 68]

The application of corrosion inhibitors to practical problems often is facilitated by basic information on the mechanism of their action. Such information, as pointed out earlier, can be obtained through numerous means other than corrosion-rate measurements and examination of the corroding surfaces. Corrosion-potential measurements and polarization techniques with externally applied emf can usually reveal the anodic or cathodic nature of inhibitors, their stability on the metal surfaces, and perhaps the importance of their concentration changes.

Overpotential measurements can furnish significant information for pickling inhibitors. An increase in overpotential is indicative of corrosion inhibition in corrosion systems of the hydrogen evolution type. In recent years the availability of numerous radioactive isotopes has made possible the application of radiotracer techniques on corrosion and corrosion inhibition studies.[46] Radiotracers, although they present many technical difficulties and health hazards, are exceedingly powerful tools for studies involving the distribution and determination of minute amounts of inhibitors. The electron microscope is another tool which can be employed effectively for adsorption and orientation studies of organic inhibitors on metal surfaces.[69]

The electrochemical nature of corrosion processes has led to the development of a number of accelerated tests which have been proposed for the evaluation and screening of inhibitors. Such tests are based on: (1) the effect of inhibitors on the current output of galvanic cells (inhibitors for oil wells),[67] (2) the suppression of polarographic maxima by inhibitors,[63] and (3) the effect of inhibitors on the anodic and cathodic polarization characteristics of metals (use of the Pearson null bridge).[70]

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***Any discussions of this article not published above will appear in the June, 1956 Issue.***

# The Investigation of an Unusual Cause of Shipbottom Pitting*

By R. P. DEVOLUY

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## Abstract

Two unusual and severe cases of shipbottom pitting were encountered within the space of a few years. Although the two incidents occurred in polluted harbors 3000 miles apart, the vessels involved showed the same symptoms. These symptoms were rapid pitting; inactivation of the blackened antifouling paint and good electrical conductivity of the black surface film. The black conversion product, found only in the upper layer of the antifouling paint, was shorted to the steel hull.

A study of the painting history of the vessels involved and of the conditions to which they were exposed in service indicated two common factors were present on ships that pitted. First, there was contact between the antifouling paint and the steel hull and secondly, there was exposure to sulfide forming waters. When one of these factors was missing, vessels exposed to the other condition did not show unusual pitting.

To confirm a theory as to the cause of pitting a series of test panels duplicating conditions experienced in service were prepared. The tests, with suitable controls tended to substantiate the theory advanced. From information so obtained it was possible to recommend simple measures that would prevent the recurrence of the severe underwater corrosion described.

## Case Histories

THE AUTHOR in November of 1952 was invited to inspect the fourth ship in a group of destroyers that had shown very severe pitting. These ships were the first group of such vessels to be painted with vinyl paints in 1950 and it was suspected that these coatings were in some way responsible for the severe localized corrosion. On first inspection, these observations were made:

1. The entire bottom was covered with a black film except for the few areas touched up a year previously. These areas had the usual gray-green color.
2. Marine fouling consisting primarily of barnacles was attached to all the black areas but not to the normal gray-green touch up spots.
3. The badly corroded areas for the most part were to be found near the turn of the bilge where the bilge keel blocks were located when the ship was on drydock. At one such location the steel plate was perforated (see Figure 1).

These observations paralleled an unusual corrosion situation investigated four years prior on steel pleasure boats; because of that development the author knew what to look for in this case. Further investigation disclosed the following:

1. The black film was adherent and seemed to be a conversion product in the upper layers of the antifouling paint. Some of the black film was scraped off and on analysis was found to contain copper sulfide, cupric oxide and iron oxide in addition to some cuprous oxide from the original pigmentation of the antifouling paint.
2. The black film was an excellent conductor and was shorted to the steel hull at corroded areas. This conductivity was a surface phenomenon because high resistance (over 200 megohms at 500 volts) was recorded when an island of the black film was made by scraping through to normal antifouling paint or to the anticorrosive coatings. The antifouling paint layers underneath were not conductive, nor was the gray-green film (probably basic-copper carbonate) present on the touch up antifouling applied at the first drydocking one year after the original paint job. Another interesting observation was that the black film, present under the normal antifouling paint-anticorrosive-primer at the touch up areas, was still a conductor and was still shorted to the hull at these pitted

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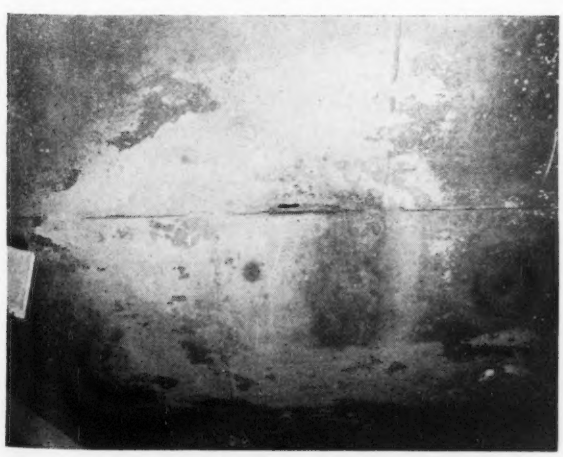

Figure 1—Pitted bilge keel block area. Light area is touch up paint applied over the black conductive film.

**Figure 2—Keel block area. Note how hull fails to completely fit the blocks. Light area is touch up paint.**

areas. This would explain why corrosion existed at these areas in spite of the touch up painting.

3. The marine fouling was general but much heavier around the corroded areas. The barnacles were attached to the black film. This is a good example of inactivation of antifouling paint, but by an unusual mechanism.
4. The total paint film thickness was 5-6 mils of which only 3 mils were undercoats. The ship's officers had complete reports on the original sandblasting and paint application. It would seem that the wash primer and the three coats of vinyl zinc chromate anticorrosive were brushed onto this vessel and on the other vessels done at the same time. However, the antifouling paint was sprayed. The significance of this apparently harmless combination of procedures will be discussed later.
5. Severe pitting was not confined entirely to the bilge keel block areas. Other spots of severe corrosion were located where the paint would be thinner, such as at lap joints, etc. In the presence of 20,000 square feet of highly conductive cathodic area it is not surprising that the weak spots in a thin anticorrosive coating allowed corrosion to take place. The depth of pitting in these miscellaneous areas would indicate that this action started long after the initiating mechanism at the bilge keel block areas.
6. The ship's officers stated that the vessel had lain at the Philadelphia Navy Yard for two months after undocking and that the ship had been on the go most of the time after that. All periods of short inactivity were checked and found to have been spent in clean waters. The anaerobic conditions in that part of Philadelphia Harbor are well known as are also the bacteria that are instrumental in the formation of sulfides.

*Previous Case of Corrosion*

A similar case of corrosion which occurred in 1948 will be discussed briefly. It will be shown how dealing with that problem helped in finding the answers to this more recent case. In the 1948 incident more than 1000 steel pleasure boats had been painted with the vinyl underwater system and shipped to various parts of the world. Under this wide variety of exposures, the boats came through with an excellent record of freedom from corrosion and fouling. Over a period of years only the group of boats in San Pedro, California gave any trouble. It should be pointed out that the boat anchorage in that harbor also is well known for its anaerobic conditions. Inspection disclosed the following conditions to exist on some of the boats:

1. Severe localized pitting was evident (located in most cases at places on the bottom where the boat had rested on the cradle during shipment from the East Coast). The pits went through the thin plating in three months in several cases.
2. The antifouling paint retained its normal gray-green color over the entire bottom except around the pitted areas. At these areas the paint turned black in the upper layers of the antifouling paint. The spread of the black film was found to be proportional to the depth of pitting. It was found also that the black areas were heavily fouled, indicating some basic change in the surface of the paint. The rest of the bottom was free of marine growth. The black film was analyzed and found to be high in copper sulfide.
3. The black film was a good conductor and was shorted to the hull at the pits. The black film also was proven to be a surface conductor whereas the normal antifouling paint underneath was not a conductor.

It was established later that the distributor had made a practice of touching up abraded paint areas (from rubbing on the cradle while in transit) with antifouling paint only. This caused minor corrosion to the boats delivered to San Diego or to Santa Barbara, but in the sulfide forming waters of San Pedro severe pitting resulted. When the proper touch up procedure was followed, the trouble stopped.

Test panels designed to duplicate these conditions showed later that other types of antifouling paints, applied in the same manner to bare steel and exposed in these waters, did the same thing. Duplicate panels in clean waters caused only minor corrosion when most types of copper oxide bearing antifouling paints were applied to bare windows in steel panels. The case then was placed in the closed file because it was though unlikely that the combination of circumstances encountered there would be met again. The fact that it has happened again, even under the careful conditions in which the Navy paints its ships, has led to this paper. The writer has spent many years observing painting practices in both Navy and private shipyards and feels that if this type of corrosion can occur on a naval vessel, it also can occur on other vessels.

*Spraying Versus Brushing*

The main difficulty in drawing a parallel between the case of the destroyers at Philadelphia and the steel boats in San Pedro was determining how antifouling paint could accidently get on bare steel in a Navy yard. Only circumstantial evidence is available but it is convincing. A few months after the inspection of the destroyer it was learned that the next group of destroyers to be painted at the same yard with the same paints was drydocked and the bottoms found to be in good condition. The only difference between the paint jobs there and on the ones that resulted in pitting was that all the coats were sprayed in the former case.

It will be recalled that the first group of ships had the undercoats brushed on and the antifouling sprayed. This condition had been associated with the low film thickness of the anticorrosive, but not with the presence of antifouling paint on bare steel. Then it was realized that the curvature of the hull at the turn of the bilge made it difficult for the bilge keel blocks to conform exactly (see Figure 2). Hence

when the hull was sandblasted some paint was removed from that area. When the undercoats were brushed there was not much chance of getting into those areas. The spray applied antifouling paint, however, could easily reach some bare metal over each block. This line of reasoning checks with the location of the severe corrosion.

It should be mentioned that a naval vessel has her position on the blocks altered at successive drydockings in order to take care of corrosion at these spots. Unfortunately, in this rare instance, the black film continued to form a conductive path under the touch up paints and thereby the entire bottom's black film acted as a cathode to these originally bare areas.

## Test Program

Inasmuch as there was some speculation involved in the above theory, a decision was made to accept Frank LaQue's invitation to run some controlled tests at the Harbor Island Test Station. The tests were designed to simulate the service conditions experienced by the steel boats and ships. Three sets of panels were prepared and exposed as follows:

Set No. 1 Immersed at Philadelphia Navy Yard for two months during the summer of 1953. The panels were kept in buckets of the same water for two additional months before being immersed in the ocean at Harbor Island in December. Test period in the ocean was six months.

Set No. 2 Immersed directly at Harbor Island; duration of test 10 months.

Set No. 3 Immersed in a ceramic croc containing sea water through which hydrogen sulfide had been bubbled for three days. Panels remained in this bath for three days more before ocean immersion for eight months.

It was necessary to make the tests in set No. 3 because Philadelphia harbor water had been considerably improved in the two year period following the ship's two months there.

### *Selection of Paint Systems*

The paint system selected included the one used on the destroyer, the one used on the boats, as well as the other basic types of paints used on the bottoms of merchant, naval and pleasure vessels. The steel test panels used were 6 inches x 12 inches and cut from ¼-inch ship plate. Surface preparation was by sandblasting. Table 1 gives the paint systems used. A full description of the bare window and antifouling paint arrangements is given in Table 2 and will be referred to as the "conditions" of exposure. These conditions (A, B, C, D) are included in Table 1 for easier understanding.

### *Conditions of Exposure*

The "conditions" of exposure for each paint system were designed to simulate what was thought to have happened in the painting of the boats and ship. Condition C is the properly painted control for each paint system: Table 2 gives the details. It is easy to see that Conditions A and B simulate what could easily happen at the bilge keel blocks, with B condition the most likely.

Condition D has both practical and theoretical importance. It was used only for Paint Systems No. 1 and No. 2 because these vinyls are used on steel piling and offshore rigs where the antifouling can be omitted. If fouling does occur, the vinyl anticorrosive is able to resist penetration by barnacles and other shell organisms and hence can still prevent corrosion.

On the theoretical side it was desirable that a check be made of the corrosion rate at the bare window without any copper oxide bearing paint on the panel. A fifth condition, similar to C but with a completely bare window probably should have been included. It was omitted because such exposures have been made many times and also because this condition is present on any shipbottom with abraded areas. Such areas rarely suffer corrosion rates comparable to the ones being discussed in this paper.

## Test Results

Table 3 includes the corrosion and fouling data for all three sets of panels immersed as previously described. The pitting data, expressed as ipy (inches per year), takes into account that the panels had windows on both sides. In one case (panel 1A in Set No. 1) the windows were out of line making it possible to measure a greater rate of pitting than in the case of windows where perforation occurred at some undetermined time.

A black conductive film was found around the windows of all the panels that suffered deep pitting. In general, the Set No. 3 panels had greater areas of black than Set No. 2. On the test panels, as on the ship and boats, the black film was shorted to the bare metal pits. The black film's potential to a calomel half cell, as measured by a glass electrode, was

**TABLE 1—Paint Systems**

| Paint System Number | Primer | Anticorrosive | Antifouling |
|---|---|---|---|
| 1 (Conditions A,B,C,D) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Vinyl Red Lead Anticorrosive MIL-P-15929 (Four Coats) | Vinyl Antifouling MIL-P-15931 (One Coat) |
| 2 (Conditions A,B,C,D) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Vinyl Zinc Chromate Anticorrosive MIL-P-15930 (Four Coats) | Vinyl Antifouling MIL-P-15931 (One Coat) |
| 3 (Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive 52 MA 401 (Three Coats) | Shipbottom Antifouling 52 MA 403a (One Coat) |
| 4 (Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive BuShips Formula No. 14 (Three Coats) | Cold Plastic Antifouling BuShips Formula No. 146 |
| 5 Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive BuShips Formula No. 14 (Three Coats) | Hot Plastic Antifouling BuShips Formula No. 15 HP (One Coat-50 mils) |

**TABLE 2—Conditions of Exposure**

| | |
|---|---|
| **Condition A** | Full paint system with a one-inch square bare window. Window covered with one coat of antifouling paint only. |
| **Condition B** | Same as "A" except the outer half of the window was coated with antifouling while the center ½-inch was kept bare. |
| **Condition C** | Full paint system on entire panel |
| **Condition D** | Antifouling paint omitted entirely. Bare window present. |

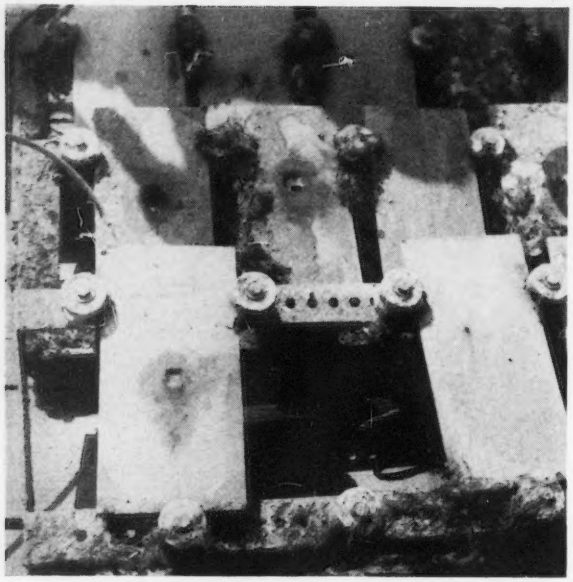

Figure 3—View of panels. Top row, left to right: 1A, 1B, 1C (all from Set No. 2); middle row, left to right: 1A, 1B, 1C (all from set No. 3); bottom row, left to right: 1A, missing, 1C (all from Set No. 1).

plus .086 volts. This means a driving force of 0.846 volts relative to steel.

Figures 3 to 6 show most of the three sets of panels. The front row is Set. No. 1, the middle row is Set No. 3 and the back row Set No. 2. This last set is the controls and they experienced little corrosion or fouling. Figure 7 shows the three cold plastic panels (4A, 4B and 4C in Set No. 3) that had the most corrosion for this type of paint. The black cold plastic was used in these tests so that it would be possible to tell if any film had formed. The inactivated areas, however, were conductive.

Of the hot plastic panels, only No. 5B in Set No. 3 formed even a small amount of black film around the

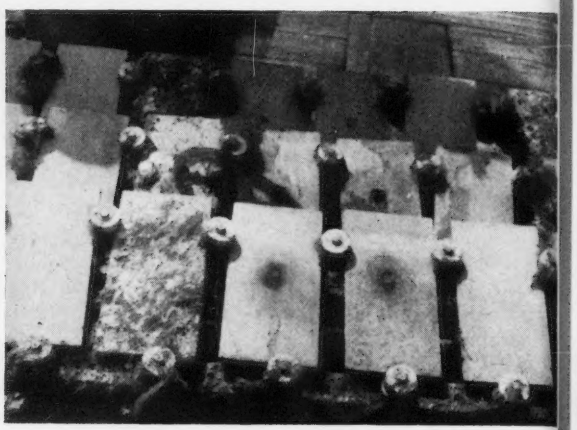

Figure 4—View of panels. Top row, left to right: 1C, 1D, 2A, 2B, 2C (all from Set No. 2); 1C, 1D, 2A, 2B, 2C (all from Set No. 3); 1C, 1D, 2A, 2B, 2C (all from Set No. 1).

window. The corrosion was moderate. Unfortunately one of the key hot plastic panels was lost during immersion.

Figures 8 and 9 illustrate the difference in corrosion rates by Paint System No. 1 depending on whether or not the panels were first exposed to Philadelphia waters as in Figure 8 or immersed directly in the ocean (see Figure 9). These paints are similar to the ones used on the destroyer and to those used by the Merchant Marine. Similar differences existed with Paint Systems 2, 3 and 4 which also are widely used paints.

### Discussion of Results

It is evident that it was possible to reproduce the conditions and results experienced on the ship and boats. The black conductive film, the inactivation and fouling, and the rates of corrosion were all consistent with the effects experienced in service. These effects occurred on Set No. 1, immersed at Phila-

**TABLE 3—Corrosion and Fouling Data**

| Paint Systems and Conditions of Exposure | Set No. 1 Philadelphia Immersion then to Ocean | | | Set No. 3 Hydrogen Sulfide Bath then to Ocean | | | Set No. 2 Direct to Ocean | | |
|---|---|---|---|---|---|---|---|---|---|
| | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) |
| 1 A | 10 | IAW[1] | .290 | 10 | ⅓ Panel Inact.[4] | >.250 Perf.[3] | 10 | 10 | None |
| 1 B | 10 | IAW[1] | >.250 Perf.[3] | 10 | ⅓ Panel Inact.[4] | >.250 Perf.[3] | 10 | Panel 10 Window 0 | Slight[2] |
| 1 C | 9 | 10 | None | 10 | 10 | None | 10 | 10 | None |
| 1 D | 10 | 0 | Slight[2] | 10 | 0 | Slight[2] | 10 | 0 | Slight[2] |
| 2 A | 9 | IAW[1] | .194 | 9 | ⅓ Panel Inact.[4] | >.250 Perf. | 10 | 10 | Slight[2] |
| 2 B | 9 | IAW[1] | .130 | 9 | ⅓ Panel Inact.[4] | >.250 Perf. | 10 | Panel 10 Window 0 | Slight[2] |
| 2 C | 9 | 10 | None | 9 | 9 | None | 10 | 10 | None |
| 2 D | 9 | 0 | Slight[2] | 9 | 0 | Slight[2] | 10 | 0 | Slight[2] |
| 3 A | 9 | 9 | Slight[2] | 9 | IAW(1) | .123 | 10 | Panel 10 Window 8 | None |
| 3 B | 10 | Panel 10 Window 0 | .034 | 9 | ⅓ Panel Inact.[4] | >.250 Perf.[3] | 10 | Panel 10 Window 0 | Slight[2] |
| 3 C | 9 | 9 | None | 9 | 10 | None | 10 | 10 | None |
| 4 A | 9 | 8 | .053 | 5-one edge gone | ⅓ Panel Inact.[4] | .126 | 9 | 10 | Slight[2] |
| 4 B | 9 | 8 | .085 | 6-bad edge | ⅓ Panel Inact.[4] | >.250 | 9 | Panel 10 Window 0 | .025 |
| 4 C | 9 | 8 | None | 5-corner gone | ⅓ Inact.[4] | Slight[2] | 9 | 10 | None |
| 5 A | 10 | 10 | None | | Panel Missing | | 10 | 10 | None |
| 5 B | 10 | 10 | .021 | 10 | Slight[2] IAW[1] | .035 | 10 | Panel 10 Window 0 | Slight[2] |
| 5 C | 10 | 10 | None | 9 | 10 | None | 10 | 10 | None |

[1] IAW—Inactivated around window.
[2] Slight pitting—10 mils or less.
[3] Perf.—Panel perforated.
[4] Inact.—Inactivated.

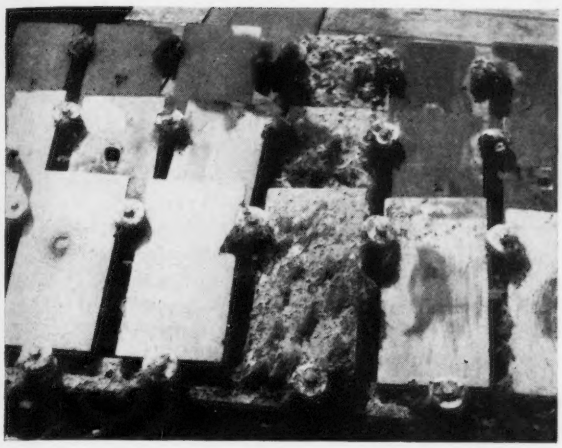

Figure 5—View of panels. Top row, left to right: 2A, 2B, 2C, 2D, 3A, 3B (all from Set No. 2); 2A, 2B, 2C, 2D, 3A, 3B (all from Set No. 3); 2B, 2C, 2D, 3A, 3B (all from Set No. 1).

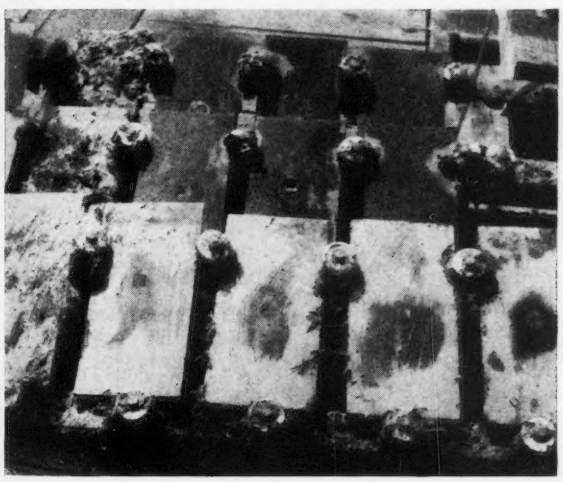

Figure 6—View of panels. Top row, left to right: 2D, 3A, 3B, 3C (all from Set No. 2); 2D, 3A, 3B, 3C (all from Set No. 3); 2D, 3A, 3B, 3C (all from Set No. 1).

delphia and then in the ocean, and also on Set No. 3 where hydrogen sulfide bath was used prior to ocean exposure. Set No. 2 showed only normal corrosion under all "conditions" because these panels were immersed directly in the ocean.

It is significant that all the paints tested, except the hot plastic, produced severe corrosion. The hot plastic was much less affected probably because of its great film thickness which would tend to insulate the sulfides from the bare steel.

Note in Table 3 that the corrosion protection and fouling resistance of all the paints was very good when exposed to normal sea water for 10 months.

Table 4 was prepared by extracting the pitting data from Table 3 and is presented for easy comparisons. In this table Condition C (no window) and Condition D (no antifouling paint) were omitted because these panels all showed only slight

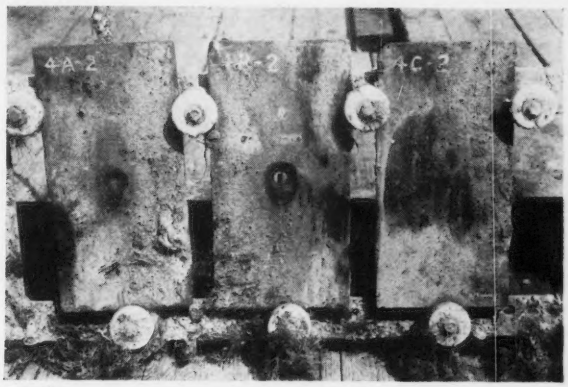


Figure 7—Cold plastic panels 4A, 4B and 4C from Set No. 3 (hydrogen sulfide bath prior to immersion in ocean).

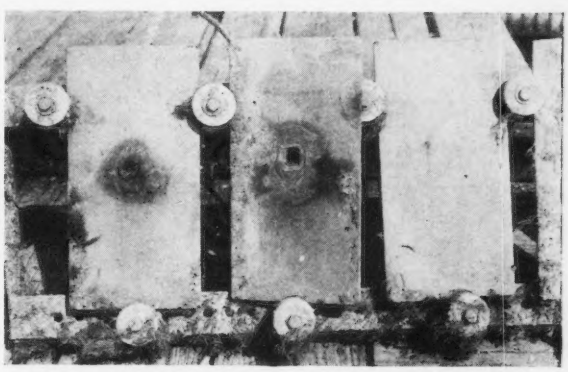

Figure 8—Vinyl paint system panels 1A, 1B and 1C from Set No. 1 (Philadelphia immersion).

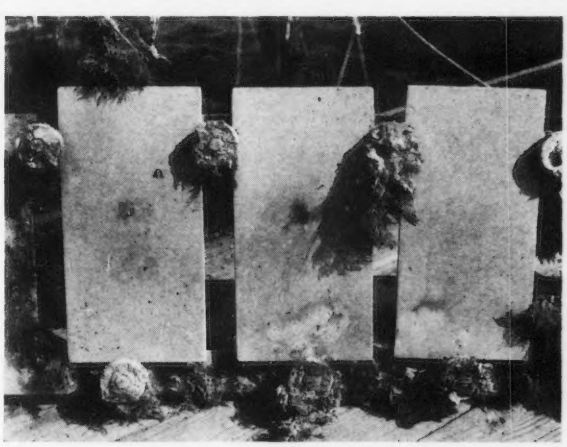

Figure 9—Vinyl paint system panels 1A, 1B and 1C from Set No. 2 (direct immersion in ocean). Note that dirt on lower half of panels came from stacking racks for composite photos.

**TABLE 4—Summary of Corrosion Data**

| | Paint Systems and Conditions of Exposure | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1A | 1B | 2A | 2B | 3A | 3B | 4A | 4B | 5A | 5B |
| Set No. 1 Philadelphia Immersion | .290 | > .250 | .194 | .130 | Slight | .034 | .053 | .085 | None | .021 |
| Set No. 3 Sulfide Bath | > .250 | > .250 | > .250 | > .250 | .123 | > .250 | .126 | > .250 | Lost | .035 |
| Set No. 2 Direct to Ocean | None | Slight | Slight | Slight | None | Slight | Slight | .025 | None | Slight |

Pitting rates are in ipy

pitting. The table is set to be studied with Figures 3 to 6.

The pitting data in Table 4 indicates that the hydrogen sulfide bath was more effective in forming the sulfide films than was Philadelphia water in 1953. In view of the ship's condition this is probably a tribute to the effective cleanup of these waters between 1951 and 1953.

Inasmuch as all the paints, except the hot plastic, contributed to the pitting under these circumstances it is not felt safe to say that one paint is less susceptible than any other.

One annoying thought persists. Why is it that this situation has not come up more often? If it had, it is likely that it would have been observed and reported. It is true that there are few ship repair yards located in such abominable waters. Furthermore ships usually do not spend two months around a repair yard after undocking.

Perhaps the answer lies in the type of surface films formed on antifouling paints. In normal sea water many antifouling paints form a bcc (basic cupric carbonate) film and it is just possible that this film is not convertible to the black copper sulfide film observed. In other words, perhaps the ship must stay in bad waters while the antifouling paint is fresh (and in contact with bare steel) or it may not later experience this trouble. More information may be obtained in a future test program.

## Conclusions

The conditions suspected as the cause of very severe pitting on some steel boats and a ship were duplicated by controlled experiments. Similar corrosion and fouling was obtained and apparently by the same mechanism.

It was shown that two conditions are necessary for this severe action:

1. Antifouling paint must be in contact with the steel.
2. The surface so painted must be exposed to sulfide bearing or sulfide forming waters.

If either of these conditions is absent, this type of corrosion does not progress.

Inasmuch as it is not possible to avoid anchoring in such waters for some periods, the only alternative is to avoid application of antifouling to bare steel. At the very least, this means that all touch up painting at bare spots etc., should be followed by a full coat of anticorrosive prior to the application of any full coat of antifouling.

It also would seem advisable when sandblasting a bottom to "fleet" the vessel and fully paint the bilge and main keel block areas. If this cannot be done then steps should be taken to ensure that the application techniques used do not allow antifouling paint to be applied where there is no anticorrosive. This is just one more reason why the anticorrosive and the antifouling should be of different color.

## Acknowledgments

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The author is indebted to Paul Ffield and Malcolm Mosher of the Bethlehem Steel Company for their suggestions and for supplying the steel panels. Frank Wagner of the Glidden Company was most helpful at the panel inspection and rating.

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The opinions expressed in this article are those of the author and not necessarily those of the Navy Department.

***Any discussions of this article not published above will appear in the June, 1956 issue.***

# Corrosion of Gasoline Engine Exhaust Valve Steels*

By C. H. ALLEN* and M. J. TAUSCHEK**


## Abstract

The corrosive environment surrounding the exhaust valves in gasoline engines is considered in connection with the types of corrosion that can occur there. Included in the discussion are valve face, valve head, valve stem and weld junction corrosion.

A method of evaluating the corrosion resistance of exhaust valve steels is given. The effect of analysis variation in the chromium-nickel, chromium-nickel-manganese and chromium-nickel-cobalt steels as it influences corrosion is presented. Other matters discussed include the influence of silicon on the corrosion of valve steels, the effect of a variation in nickel-iron content on aircraft valves, and the use of valve rotators in reducing exhaust valve corrosion.


## Introduction

THE CORROSION of exhaust valves for many years has constituted a limit to the durability of gasoline engines. The problem, serious enough in the early days, was intensified by the introduction of tetraethyl lead. As the economic advantages of this material in raising the octane value of gasolines were realized, exhaust valve corrosion problems became more serious. This situation came about partly as the result of the products of combustion but to a greater extent because of the higher engine output made possible by increased octane value.

As engine output per unit size increased the exhaust valve temperature increased considerably. Metallurgists have sought for some time to design exhaust valve alloys that are resistant to corrosion at high temperatures and, in particular, to the products of combustion of leaded gasolines. The purpose of this paper is to review some of the efforts made and to determine where future improvements may lie in corrosion resistant exhaust valve steels.

The fact that exhaust valves should corrode is not difficult to understand when consideration is given to the chemical environment in which they operate. The combustion of a typical motor gasoline will yield appreciable quantities of free oxygen, lead, bromine, chlorine and sulfur in the exhaust gases, plus lesser amounts of many other materials. It should be remembered also that these exhaust gases come in contact with the valves while they are very hot; it is not inconceivable that the surface temperatures on some parts of the valve could exceed 2000 F. While it is difficult to determine the exact surface temperatures the average mean temperatures of the internal valve structure are known (See Figure 1).

In passenger car engines the temperature at the valve head where there is exposure to gases in the combustion chamber averages about 1200 F; on the underhead area where the valve is in the path of the exhaust gas stream the temperatures reach 1300 F. The situation is more severe in heavy duty engines and temperatures there may well exceed 1600 F. There is considerable variation in valve temperatures between engines of different designs and this fact may help to explain why valve corrosion is more of a problem in some engines than in others.

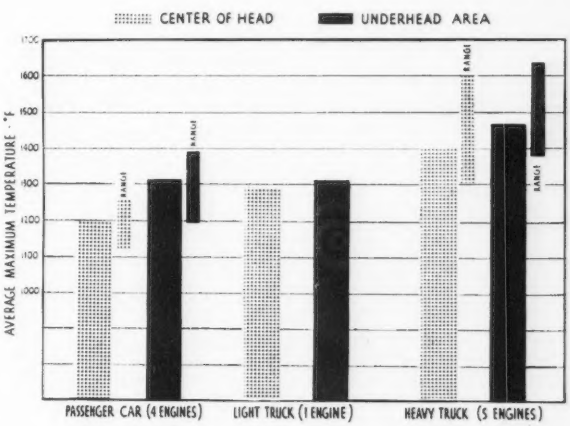


Figure 1—Valve temperature versus engine installation.

## Areas Likely to Corrode

Valves quite often burn or fail through corrosion of the seating face where they close against the valve seat (See Figure 2). Corrosion in such an area is particularly serious inasmuch as this type of corrosion

Figure 2—Typical valve face corrosion.

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# The Investigation of an Unusual Cause of Shipbottom Pitting*

By R. P. DEVOLUY

R. P. DEVOLUY—Marine manager of the Glidden Company, New York City. He first became interested in corrosion while studying engineering at City College of New York where he wrote a thesis on graphitic corrosion as his MS thesis in 1936. While serving as Assistant Laboratory Officer, Material Laboratory, New York Naval Shipyard during 1941-45 he was actively engaged in corrosion work. He is chairman of NACE Technical Practices Committee 6 C on Protective Coatings for Resistance to Marine Corrosion.

## Abstract

Two unusual and severe cases of shipbottom pitting were encountered within the space of a few years. Although the two incidents occurred in polluted harbors 3000 miles apart, the vessels involved showed the same symptoms. These symptoms were rapid pitting, inactivation of the blackened antifouling paint and good electrical conductivity of the black surface film. The black conversion product, found only in the upper layer of the antifouling paint, was shorted to the steel hull.

A study of the painting history of the vessels involved and of the conditions to which they were exposed in service indicated two common factors were present on ships that pitted. First, there was contact between the antifouling paint and the steel hull and secondly, there was exposure to sulfide forming waters. When one of these factors was missing, vessels exposed to the other condition did not show unusual pitting.

To confirm a theory as to the cause of pitting a series of test panels duplicating conditions experienced in service were prepared. The tests, with suitable controls tended to substantiate the theory advanced. From information so obtained it was possible to recommend simple measures that would prevent the recurrence of the severe underwater corrosion described.

## Case Histories

THE AUTHOR in November of 1952 was invited to inspect the fourth ship in a group of destroyers that had shown very severe pitting. These ships were the first group of such vessels to be painted with vinyl paints in 1950 and it was suspected that these coatings were in some way responsible for the severe localized corrosion. On first inspection, these observations were made:

1. The entire bottom was covered with a black film except for the few areas touched up a year previously. These areas had the usual gray-green color.
2. Marine fouling consisting primarily of barnacles was attached to all the black areas but not to the normal gray-green touch up spots.
3. The badly corroded areas for the most part were to be found near the turn of the bilge where the bilge keel blocks were located when the ship was on drydock. At one such location the steel plate was perforated (see Figure 1).

These observations paralleled an unusual corrosion situation investigated four years prior on steel pleasure boats; because of that development the author knew what to look for in this case. Further investigation disclosed the following:

1. The black film was adherent and seemed to be a conversion product in the upper layers of the antifouling paint. Some of the black film was scraped off and on analysis was found to contain copper sulfide, cupric oxide and iron oxide in addition to some cuprous oxide from the original pigmentation of the antifouling paint.
2. The black film was an excellent conductor and was shorted to the steel hull at corroded areas. This conductivity was a surface phenomenon because high resistance (over 200 megohms at 500 volts) was recorded when an island of the black film was made by scraping through to normal antifouling paint or to the anticorrosive coatings. The antifouling paint layers underneath were not conductive, nor was the gray-green film (probably basic-copper carbonate) present on the touch up antifouling applied at the first drydocking one year after the original paint job. Another interesting observation was that the black film, present under the normal antifouling paint-anticorrosive-primer at the touch up areas, was still a conductor and was still shorted to the hull at these pitted

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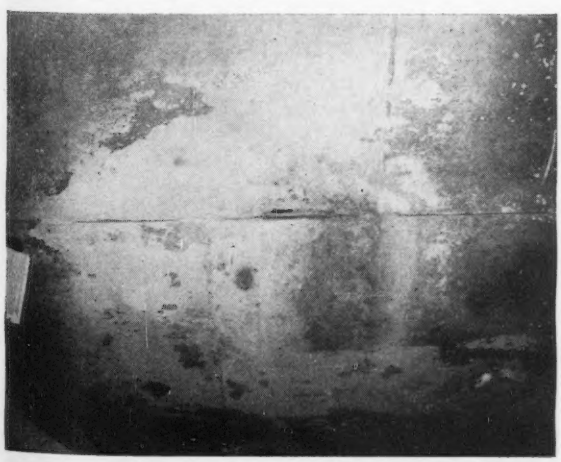

Figure 1—Pitted bilge keel block area. Light area is touch up paint applied over the black conductive film.

**Figure 2—Keel block area. Note how hull fails to completely fit the blocks. Light area is touch up paint.**

areas. This would explain why corrosion existed at these areas in spite of the touch up painting.

3. The marine fouling was general but much heavier around the corroded areas. The barnacles were attached to the black film. This is a good example of inactivation of antifouling paint, but by an unusual mechanism.
4. The total paint film thickness was 5-6 mils of which only 3 mils were undercoats. The ship's officers had complete reports on the original sandblasting and paint application. It would seem that the wash primer and the three coats of vinyl zinc chromate anticorrosive were brushed onto this vessel and on the other vessels done at the same time. However, the antifouling paint was sprayed. The significance of this apparently harmless combination of procedures will be discussed later.
5. Severe pitting was not confined entirely to the bilge keel block areas. Other spots of severe corrosion were located where the paint would be thinner, such as at lap joints, etc. In the presence of 20,000 square feet of highly conductive cathodic area it is not surprising that the weak spots in a thin anticorrosive coating allowed corrosion to take place. The depth of pitting in these miscellaneous areas would indicate that this action started long after the initiating mechanism at the bilge keel block areas.
6. The ship's officers stated that the vessel had lain at the Philadelphia Navy Yard for two months after undocking and that the ship had been on the go most of the time after that. All periods of short inactivity were checked and found to have been spent in clean waters. The anaerobic conditions in that part of Philadelphia Harbor are well known as are also the bacteria that are instrumental in the formation of sulfides.

*Previous Case of Corrosion*

A similar case of corrosion which occurred in 1948 will be discussed briefly. It will be shown how dealing with that problem helped in finding the answers to this more recent case. In the 1948 incident more than 1000 steel pleasure boats had been painted with the vinyl underwater system and shipped to various parts of the world. Under this wide variety of exposures, the boats came through with an excellent record of freedom from corrosion and fouling. Over a period of years only the group of boats in San Pedro, California gave any trouble. It should be pointed out that the boat anchorage in that harbor also is well known for its anaerobic conditions. Inspection disclosed the following conditions to exist on some of the boats:

1. Severe localized pitting was evident (located in most cases at places on the bottom where the boat had rested on the cradle during shipment from the East Coast). The pits went through the thin plating in three months in several cases.
2. The antifouling paint retained its normal gray-green color over the entire bottom except around the pitted areas. At these areas the paint turned black in the upper layers of the antifouling paint. The spread of the black film was found to be proportional to the depth of pitting. It was found also that the black areas were heavily fouled, indicating some basic change in the surface of the paint. The rest of the bottom was free of marine growth. The black film was analyzed and found to be high in copper sulfide.
3. The black film was a good conductor and was shorted to the hull at the pits. The black film also was proven to be a surface conductor whereas the normal antifouling paint underneath was not a conductor.

It was established later that the distributor had made a practice of touching up abraded paint areas (from rubbing on the cradle while in transit) with antifouling paint only. This caused minor corrosion to the boats delivered to San Diego or to Santa Barbara, but in the sulfide forming waters of San Pedro severe pitting resulted. When the proper touch up procedure was followed, the trouble stopped.

Test panels designed to duplicate these conditions showed later that other types of antifouling paints, applied in the same manner to bare steel and exposed in these waters, did the same thing. Duplicate panels in clean waters caused only minor corrosion when most types of copper oxide bearing antifouling paints were applied to bare windows in steel panels. The case then was placed in the closed file because it was though unlikely that the combination of circumstances encountered there would be met again. The fact that it has happened again, even under the careful conditions in which the Navy paints its ships, has led to this paper. The writer has spent many years observing painting practices in both Navy and private shipyards and feels that if this type of corrosion can occur on a naval vessel, it also can occur on other vessels.

*Spraying Versus Brushing*

The main difficulty in drawing a parallel between the case of the destroyers at Philadelphia and the steel boats in San Pedro was determining how antifouling paint could accidently get on bare steel in a Navy yard. Only circumstantial evidence is available but it is convincing. A few months after the inspection of the destroyer it was learned that the next group of destroyers to be painted at the same yard with the same paints was drydocked and the bottoms found to be in good condition. The only difference between the paint jobs there and on the ones that resulted in pitting was that all the coats were sprayed in the former case.

It will be recalled that the first group of ships had the undercoats brushed on and the antifouling sprayed. This condition had been associated with the low film thickness of the anticorrosive, but not with the presence of antifouling paint on bare steel. Then it was realized that the curvature of the hull at the turn of the bilge made it difficult for the bilge keel blocks to conform exactly (see Figure 2). Hence

when the hull was sandblasted some paint was removed from that area. When the undercoats were brushed there was not much chance of getting into those areas. The spray applied antifouling paint, however, could easily reach some bare metal over each block. This line of reasoning checks with the location of the severe corrosion.

It should be mentioned that a naval vessel has her position on the blocks altered at successive drydockings in order to take care of corrosion at these spots. Unfortunately, in this rare instance, the black film continued to form a conductive path under the touch up paints and thereby the entire bottom's black film acted as a cathode to these originally bare areas.

## Test Program

Inasmuch as there was some speculation involved in the above theory, a decision was made to accept Frank LaQue's invitation to run some controlled tests at the Harbor Island Test Station. The tests were designed to simulate the service conditions experienced by the steel boats and ships. Three sets of panels were prepared and exposed as follows:

Set No. 1 Immersed at Philadelphia Navy Yard for two months during the summer of 1953. The panels were kept in buckets of the same water for two additional months before being immersed in the ocean at Harbor Island in December. Test period in the ocean was six months.

Set No. 2 Immersed directly at Harbor Island; duration of test 10 months.

Set No. 3 Immersed in a ceramic croc containing sea water through which hydrogen sulfide had been bubbled for three days. Panels remained in this bath for three days more before ocean immersion for eight months.

It was necessary to make the tests in set No. 3 because Philadelphia harbor water had been considerably improved in the two year period following the ship's two months there.

### *Selection of Paint Systems*

The paint system selected included the one used on the destroyer, the one used on the boats, as well as the other basic types of paints used on the bottoms of merchant, naval and pleasure vessels. The steel test panels used were 6 inches x 12 inches and cut from ¼-inch ship plate. Surface preparation was by sandblasting. Table 1 gives the paint systems used. A full description of the bare window and antifouling paint arrangements is given in Table 2 and will be referred to as the "conditions" of exposure. These conditions (A, B, C, D) are included in Table 1 for easier understanding.

### *Conditions of Exposure*

The "conditions" of exposure for each paint system were designed to simulate what was thought to have happened in the painting of the boats and ship. Condition C is the properly painted control for each paint system: Table 2 gives the details. It is easy to see that Conditions A and B simulate what could easily happen at the bilge keel blocks, with B condition the most likely.

Condition D has both practical and theoretical importance. It was used only for Paint Systems No. 1 and No. 2 because these vinyls are used on steel piling and offshore rigs where the antifouling can be omitted. If fouling does occur, the vinyl anticorrosive is able to resist penetration by barnacles and other shell organisms and hence can still prevent corrosion.

On the theoretical side it was desirable that a check be made of the corrosion rate at the bare window without any copper oxide bearing paint on the panel. A fifth condition, similar to C but with a completely bare window probably should have been included. It was omitted because such exposures have been made many times and also because this condition is present on any shipbottom with abraded areas. Such areas rarely suffer corrosion rates comparable to the ones being discussed in this paper.

## Test Results

Table 3 includes the corrosion and fouling data for all three sets of panels immersed as previously described. The pitting data, expressed as ipy (inches per year), takes into account that the panels had windows on both sides. In one case (panel 1A in Set No. 1) the windows were out of line making it possible to measure a greater rate of pitting than in the case of windows where perforation occurred at some undetermined time.

A black conductive film was found around the windows of all the panels that suffered deep pitting. In general, the Set No. 3 panels had greater areas of black than Set No. 2. On the test panels, as on the ship and boats, the black film was shorted to the bare metal pits. The black film's potential to a calomel half cell, as measured by a glass electrode, was

**TABLE 1—Paint Systems**

| Paint System Number | Primer | Anticorrosive | Antifouling |
|---|---|---|---|
| 1 (Conditions A,B,C,D) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Vinyl Red Lead Anticorrosive MIL-P-15929 (Four Coats) | Vinyl Antifouling MIL-P-15931 (One Coat) |
| 2 (Conditions A,B,C,D) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Vinyl Zinc Chromate Anticorrosive MIL-P-15930 (Four Coats) | Vinyl Antifouling MIL-P-15931 (One Coat) |
| 3 (Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive 52 MA 401 (Three Coats) | Shipbottom Antifouling 52 MA 403a (One Coat) |
| 4 (Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive BuShips Formula No. 14 (Three Coats) | Cold Plastic Antifouling BuShips Formula No. 146 |
| 5 Conditions A,B,C) | Vinyl Wash Primer MIL-P-15328 (One Coat) | Shipbottom Anticorrosive BuShips Formula No. 14 (Three Coats) | Hot Plastic Antifouling BuShips Formula No. 15 HP (One Coat-50 mils) |

**TABLE 2—Conditions of Exposure**

| | |
|---|---|
| **Condition A** | Full paint system with a one-inch square bare window. Window covered with one coat of antifouling paint only. |
| **Condition B** | Same as "A" except the outer half of the window was coated with antifouling while the center ½-inch was kept bare. |
| **Condition C** | Full paint system on entire panel |
| **Condition D** | Antifouling paint omitted entirely. Bare window present. |

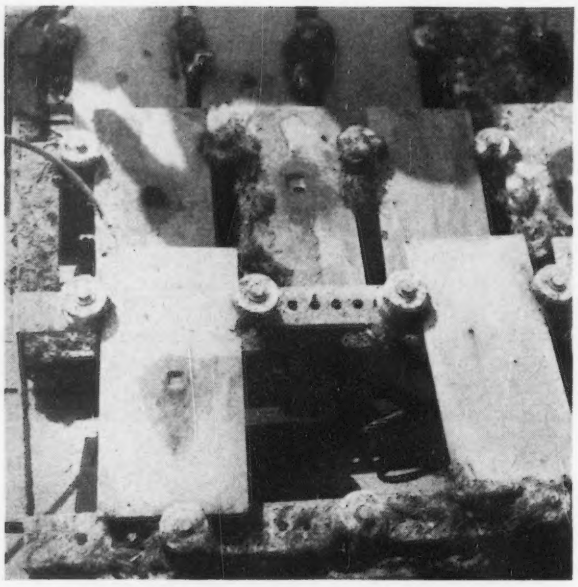

Figure 3—View of panels. Top row, left to right: 1A, 1B, 1C (all from Set No. 2); middle row, left to right: 1A, 1B, 1C (all from set No. 3); bottom row, left to right: 1A, missing, 1C (all from Set No. 1).

plus .086 volts. This means a driving force of 0.846 volts relative to steel.

Figures 3 to 6 show most of the three sets of panels. The front row is Set. No. 1, the middle row is Set No. 3 and the back row Set No. 2. This last set is the controls and they experienced little corrosion or fouling. Figure 7 shows the three cold plastic panels (4A, 4B and 4C in Set No. 3) that had the most corrosion for this type of paint. The black cold plastic was used in these tests so that it would be possible to tell if any film had formed. The inactivated areas, however, were conductive.

Of the hot plastic panels, only No. 5B in Set No. 3 formed even a small amount of black film around the

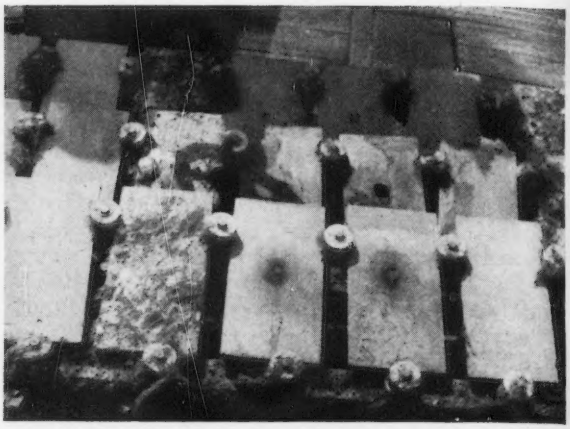

Figure 4—View of panels. Top row, left to right: 1C, 1D, 2A, 2B, 2C (all from Set No. 2); 1C, 1D, 2A, 2B, 2C (all from Set No. 3); 1C, 1D, 2A, 2B, 2C (all from Set No. 1).

window. The corrosion was moderate. Unfortunately one of the key hot plastic panels was lost during immersion.

Figures 8 and 9 illustrate the difference in corrosion rates by Paint System No. 1 depending on whether or not the panels were first exposed to Philadelphia waters as in Figure 8 or immersed directly in the ocean (see Figure 9). These paints are similar to the ones used on the destroyer and to those used by the Merchant Marine. Similar differences existed with Paint Systems 2, 3 and 4 which also are widely used paints.

### Discussion of Results

It is evident that it was possible to reproduce the conditions and results experienced on the ship and boats. The black conductive film, the inactivation and fouling, and the rates of corrosion were all consistent with the effects experienced in service. These effects occurred on Set No. 1, immersed at Phila-

**TABLE 3—Corrosion and Fouling Data**

| Paint Systems and Conditions of Exposure | Set No. 1 Philadelphia Immersion then to Ocean | | | Set No. 3 Hydrogen Sulfide Bath then to Ocean | | | Set No. 2 Direct to Ocean | | |
|---|---|---|---|---|---|---|---|---|---|
| | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) | General Corrosion Rating | Fouling or Inactivation | Pitting (ipy) |
| 1 A | 10 | IAW[1] | .290 | 10 | ½ Panel Inact.[4] | > .250 Perf.[3] | 10 | 10 | None |
| 1 B | 10 | IAW[1] | > .250 Perf.[3] | 10 | ½ Panel Inact.[4] | > .250 Perf.[3] | 10 | Panel 10 Window 0 | Slight[2] |
| 1 C | 9 | 10 | None | 10 | 10 | None | 10 | 10 | None |
| 1 D | 10 | 0 | Slight[2] | 10 | 0 | Slight[2] | 10 | 0 | Slight[2] |
| 2 A | 9 | IAW[1] | .194 | 9 | ½ Panel Inact.[4] | > .250 Perf. | 10 | 10 | Slight[2] |
| 2 B | 9 | IAW[1] | .130 | 9 | ½ Panel Inact.[4] | > .250 Perf. | 10 | Panel 10 Window 0 | Slight[2] |
| 2 C | 9 | 10 | None | 9 | 9 | None | 10 | 10 | None |
| 2 D | 9 | 0 | Slight[2] | 9 | 0 | Slight[2] | 10 | 0 | Slight[2] |
| 3 A | 9 | 9 | Slight[2] | 9 | IAW(1) | .123 | 10 | Panel 10 Window 8 | None |
| 3 B | 10 | Panel 10 Window 0 | .034 | 9 | ½ Panel Inact.[4] | > .250 Perf.[3] | 10 | Panel 10 Window 0 | Slight[2] |
| 3 C | 9 | 9 | None | 9 | 10 | None | 10 | 10 | None |
| 4 A | 9 | 8 | .053 | 5-one edge gone | ½ Panel Inact.[4] | .126 | 9 | 10 | Slight[2] |
| 4 B | 9 | 8 | .085 | 6-bad edge | ½ Panel Inact.[4] | > .250 | 9 | Panel 10 Window 0 | .025 |
| 4 C | 9 | 8 | None | 5-corner gone | ⅓ Inact.[4] | Slight[2] | 9 | 10 | None |
| 5 A | 10 | 10 | None | | Panel Missing | | 10 | 10 | None |
| 5 B | 10 | 10 | .021 | 10 | Slight[2] IAW[1] | .035 | 10 | Panel 10 Window 0 | Slight[2] |
| 5 C | 10 | 10 | None | 9 | 10 | None | 10 | 10 | None |

[1] IAW—Inactivated around window.
[2] Slight pitting—10 mils or less.
[3] Perf.—Panel perforated.
[4] Inact.—Inactivated.

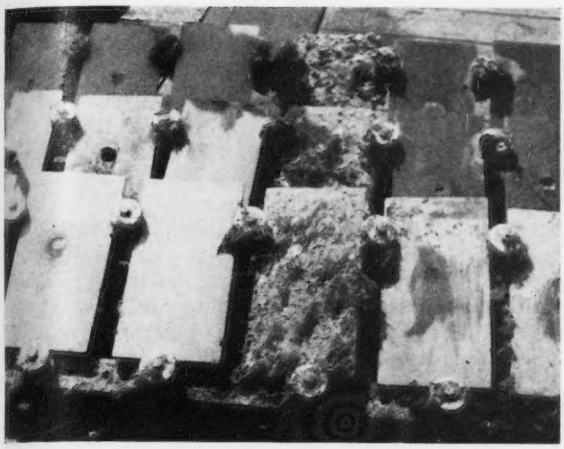

Figure 5—View of panels. Top row, left to right: 2A, 2B, 2C, 2D, 3A, 3B (all from Set No. 2); 2A, 2B, 2C, 2D, 3A, 3B (all from Set No. 3); 2B, 2C, 2D, 3A, 3B (all from Set No. 1).

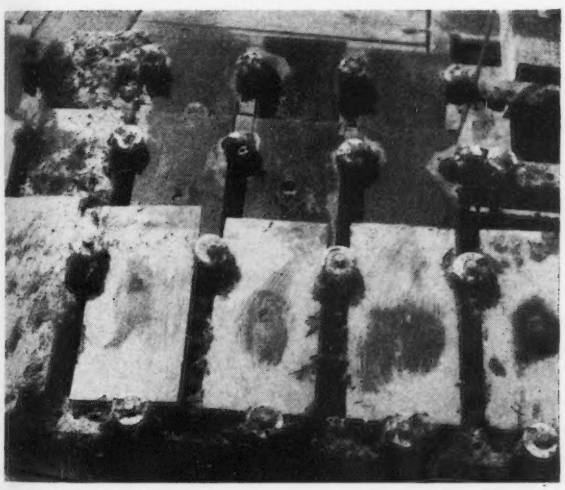

Figure 6—View of panels. Top row, left to right: 2D, 3A, 3B, 3C (all from Set No. 2); 2D, 3A, 3B, 3C (all from Set No. 3); 2D, 3A, 3B, 3C (all from Set No. 1).

delphia and then in the ocean, and also on Set No. 3 where hydrogen sulfide bath was used prior to ocean exposure. Set No. 2 showed only normal corrosion under all "conditions" because these panels were immersed directly in the ocean.

It is significant that all the paints tested, except the hot plastic, produced severe corrosion. The hot plastic was much less affected probably because of its great film thickness which would tend to insulate the sulfides from the bare steel.

Note in Table 3 that the corrosion protection and fouling resistance of all the paints was very good when exposed to normal sea water for 10 months.

Table 4 was prepared by extracting the pitting data from Table 3 and is presented for easy comparisons. In this table Condition C (no window) and Condition D (no antifouling paint) were omitted because these panels all showed only slight

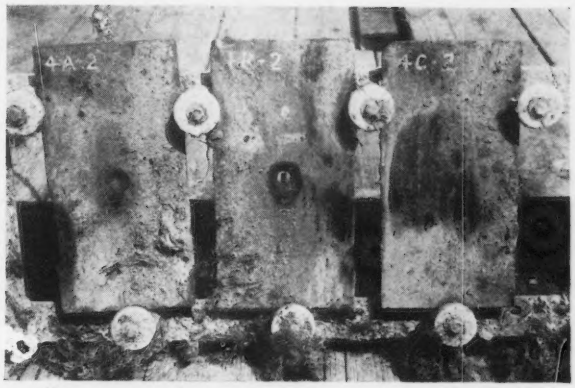


Figure 7—Cold plastic panels 4A, 4B and 4C from Set No. 3 (hydrogen sulfide bath prior to immersion in ocean).

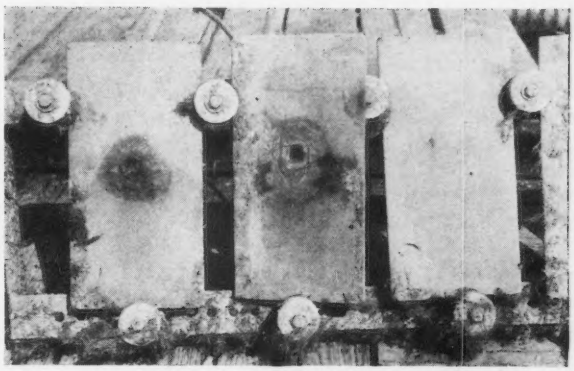

Figure 8—Vinyl paint system panels 1A, 1B and 1C from Set No. 1 (Philadelphia immersion).

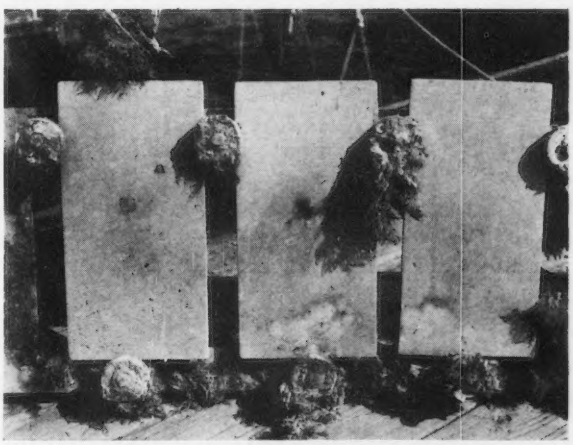

Figure 9—Vinyl paint system panels 1A, 1B and 1C from Set No. 2 (direct immersion in ocean). Note that dirt on lower half of panels came from stacking racks for composite photos.

**TABLE 4—Summary of Corrosion Data**

| | Paint Systems and Conditions of Exposure | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 A | 1 B | 2 A | 2 B | 3 A | 3 B | 4 A | 4 B | 5 A | 5 B |
| Set No. 1 Philadelphia Immersion..... | .290 | > .250 | .194 | .130 | Slight | .034 | .053 | .085 | None | .021 |
| Set No. 3 Sulfide Bath | > .250 | > .250 | > .250 | > .250 | .123 | > .250 | .126 | > .250 | Lost | .035 |
| Set No. 2 Direct to Ocean..... | None | Slight | Slight | Slight | None | Slight | Slight | .025 | None | Slight |

Pitting rates are in ipy

pitting. The table is set to be studied with Figures 3 to 6.

The pitting data in Table 4 indicates that the hydrogen sulfide bath was more effective in forming the sulfide films than was Philadelphia water in 1953. In view of the ship's condition this is probably a tribute to the effective cleanup of these waters between 1951 and 1953.

Inasmuch as all the paints, except the hot plastic, contributed to the pitting under these circumstances it is not felt safe to say that one paint is less susceptible than any other.

One annoying thought persists. Why is it that this situation has not come up more often? If it had, it is likely that it would have been observed and reported. It is true that there are few ship repair yards located in such abominable waters. Furthermore ships usually do not spend two months around a repair yard after undocking.

Perhaps the answer lies in the type of surface films formed on antifouling paints. In normal sea water many antifouling paints form a bcc (basic cupric carbonate) film and it is just possible that this film is not convertible to the black copper sulfide film observed. In other words, perhaps the ship must stay in bad waters while the antifouling paint is fresh (and in contact with bare steel) or it may not later experience this trouble. More information may be obtained in a future test program.

## Conclusions

The conditions suspected as the cause of very severe pitting on some steel boats and a ship were duplicated by controlled experiments. Similar corrosion and fouling was obtained and apparently by the same mechanism.

It was shown that two conditions are necessary for this severe action:

1. Antifouling paint must be in contact with the steel.
2. The surface so painted must be exposed to sulfide bearing or sulfide forming waters.

If either of these conditions is absent, this type of corrosion does not progress.

Inasmuch as it is not possible to avoid anchoring in such waters for some periods, the only alternative is to avoid application of antifouling to bare steel. At the very least, this means that all touch up painting at bare spots etc., should be followed by a full coat of anticorrosive prior to the application of any full coat of antifouling.

It also would seem advisable when sandblasting a bottom to "fleet" the vessel and fully paint the bilge and main keel block areas. If this cannot be done then steps should be taken to ensure that the application techniques used do not allow antifouling paint to be applied where there is no anticorrosive. This is just one more reason why the anticorrosive and the antifouling should be of different color.

## Acknowledgments

The author thanks Commander R. T. Miller, U. S. N., for calling attention to this ship's corrosion problem and Robert Burnett, Boston Naval Shipyard, for his help at the inspection. Daniel P. Graham and Frank Van Etten of the Bureau of Ships helped to design the test program. Walter Cranmer and Arthur De Marco of the Industrial Test Laboratory, Philadelphia Naval Shipyard, prepared the test panels with the Navy paints and helped at their inspection. The remainder of the test panels were prepared by the writer's former associates at the C. A. Woolsey Paint and Color Company.

The author is indebted to Paul Ffield and Malcolm Mosher of the Bethlehem Steel Company for their suggestions and for supplying the steel panels. Frank Wagner of the Glidden Company was most helpful at the panel inspection and rating.

Mr. LaQue and Dr. Tom May of the International Nickel Company gave valuable advice and offered the use of the excellent facilities of their Harbor Island Test Station. Harry Patterson and R. B. Teel did their usual efficient job of handling the test panel exposures and accompanying arrangements.

The opinions expressed in this article are those of the author and not necessarily those of the Navy Department.

***Any discussions of this article not published above will appear in the June, 1956 issue.***

# Corrosion of Gasoline Engine Exhaust Valve Steels*

By C. H. ALLEN* and M. J. TAUSCHEK**


## Abstract

The corrosive environment surrounding the exhaust valves in gasoline engines is considered in connection with the types of corrosion that can occur there. Included in the discussion are valve face, valve head, valve stem and weld junction corrosion.

A method of evaluating the corrosion resistance of exhaust valve steels is given. The effect of analysis variation in the chromium-nickel, chromium-nickel-manganese and chromium-nickel-cobalt steels as it influences corrosion is presented. Other matters discussed include the influence of silicon on the corrosion of valve steels, the effect of a variation in nickel-iron content on aircraft valves, and the use of valve rotators in reducing exhaust valve corrosion.


## Introduction

THE CORROSION of exhaust valves for many years has constituted a limit to the durability of gasoline engines. The problem, serious enough in the early days, was intensified by the introduction of tetraethyl lead. As the economic advantages of this material in raising the octane value of gasolines were realized, exhaust valve corrosion problems became more serious. This situation came about partly as the result of the products of combustion but to a greater extent because of the higher engine output made possible by increased octane value.

As engine output per unit size increased the exhaust valve temperature increased considerably. Metallurgists have sought for some time to design exhaust valve alloys that are resistant to corrosion at high temperatures and, in particular, to the products of combustion of leaded gasolines. The purpose of this paper is to review some of the efforts made and to determine where future improvements may lie in corrosion resistant exhaust valve steels.

The fact that exhaust valves should corrode is not difficult to understand when consideration is given to the chemical environment in which they operate. The combustion of a typical motor gasoline will yield appreciable quantities of free oxygen, lead, bromine, chlorine and sulfur in the exhaust gases, plus lesser amounts of many other materials. It should be remembered also that these exhaust gases come in contact with the valves while they are very hot; it is not inconceivable that the surface temperatures on some parts of the valve could exceed 2000 F. While it is difficult to determine the exact surface temperatures the average mean temperatures of the internal valve structure are known (See Figure 1).

In passenger car engines the temperature at the valve head where there is exposure to gases in the combustion chamber averages about 1200 F; on the underhead area where the valve is in the path of the exhaust gas stream the temperatures reach 1300 F. The situation is more severe in heavy duty engines and temperatures there may well exceed 1600 F. There is considerable variation in valve temperatures between engines of different designs and this fact may help to explain why valve corrosion is more of a problem in some engines than in others.

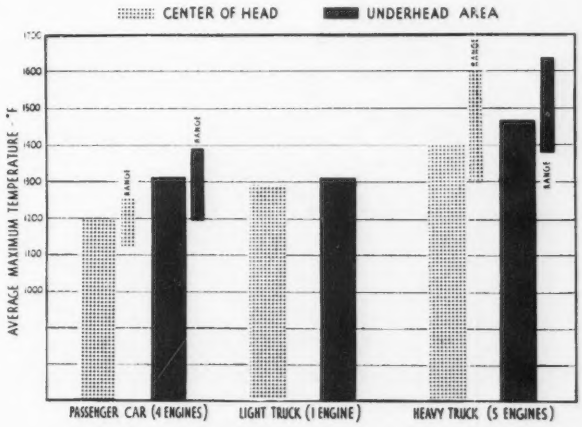


Figure 1—Valve temperature versus engine installation.

## Areas Likely to Corrode

Valves quite often burn or fail through corrosion of the seating face where they close against the valve seat (See Figure 2). Corrosion in such an area is particularly serious inasmuch as this type of corrosion

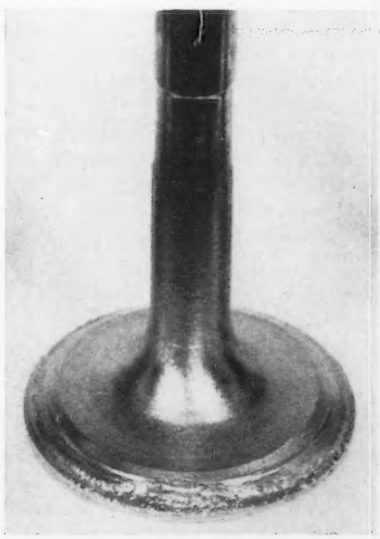

Figure 2—Typical valve face corrosion.

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Figure 3—Typical valve head corrosion.

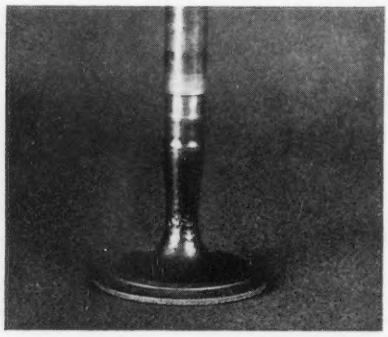

Figure 4—Typical valve stem corrosion.

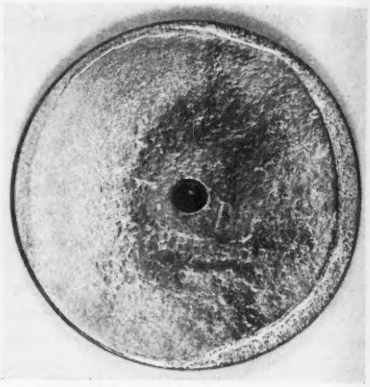

Figure 5—Typical weld junction corrosion.

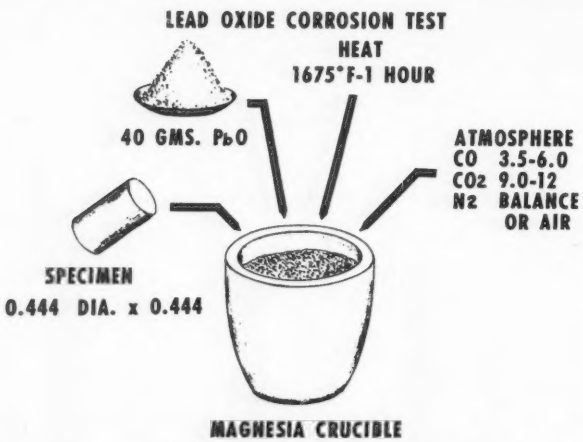


Figure 6—Test procedure for measuring the resistance of a material to corrosion in molten lead oxide.

interferes with the seal and thus allows combustion gases to leak past the valve face. Such leakage raises the valve head temperature markedly—in some instances as much as 300 - 400 F—and thus accelerates the corrosion that already is occurring. Ultimately, the reaction becomes so rapid that the valve cannot effectively close off the combustion chamber and the engine will no longer operate satisfactorily.

Other types of corrosion also can occur on exhaust valves. Corrosion of the top of the valve head (See Figure 3) frequently is encountered but this corrosion is not so serious as the face corrosion inasmuch as it does not interfere with the functioning of the valve. Of course, if sufficient material corrodes, the valve will lose its structural strength and thus fail.

Corrosion can occur also on the stem portion of the valve (See Figure 4). Corrosion of this type, if unchecked, can lead to failure of the valve through breakage at the corroded area and subsequently can cause a great deal of damage to the engine. Fortunately, failures of this type are not frequent but the fact that they occasionally do occur must be recognized.

Still another form of corrosion occurs on faced exhaust valves. In this type of valve construction, a highly corrosion-resistant material is welded to the valve base material at the seat face in order to prevent some of the face corrosion described previously. Accelerated corrosion sometimes will occur at the juncture between the two materials (Figure 5). Such corrosion preferentially attacks the valve base material and weakens the support behind the welded layer. Ultimately such corrosion will cause distortion and cracking of the valve face.

### Corrosive Elements in Exhaust Stream

It is particularly difficult to determine just what elements in the exhaust stream cause valve corrosion to occur. It is known that tetraethyl lead plays a part in this but not all corrosion can be attributed to lead. Other elements such as the sulfur may have a marked influence on corrosion. It is known also that any free oxygen in the exhaust gas stream will accelerate oxidation of the valve steels.

Deposit forming elements in the fuel or lubricating oil can influence corrosion by forming deposit layers between the valve and the seat. These deposits may lead to solid-state reactions which induce valve face corrosion. Once again, local ruptures in the deposit layers permit combustion gas leakage to occur. Such leakage raises the valve temperature and has an important effect in accelerating valve corrosion.

In developing suitable alloys for use in exhaust valves it is necessary to have some type of laboratory bench test that can be used for screening purposes. The company's laboratories have devised a test procedure which measures the resistance of the material to corrosion in molten lead oxide (See Figure 6). In this test, a sample of the material is placed in a crucible together with lead oxide and heated to 1675 F for one hour. The weight loss of the specimen is then determined and the loss used as a means of expressing the relative corrosion resistance of the alloy.

The test does not take into consideration the effects of bromine and chlorine present in the exhaust gases, nor does it concern itself with any of the other elements ordinarily found in gasoline. Nevertheless, experience has shown that it correlates fairly well with tests conducted in engines and therefore has a certain amount of usefulness in developing new valve alloys. It should be pointed out, however, that final proof can be obtained only from actual engine tests. This is because so many variables are encountered relating to the engine design, the fuel, the lubricant and other factors.

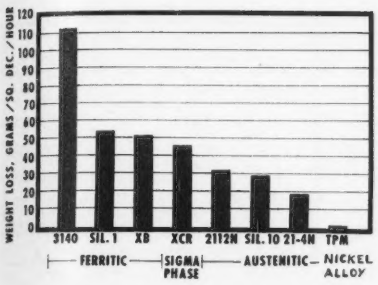


Figure 7—Corrosion resistance of conventional valve alloys.

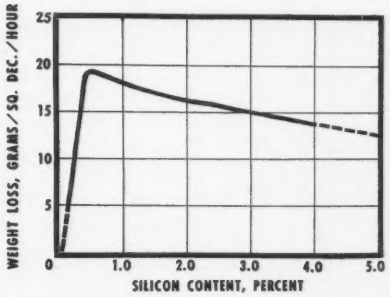


Figure 8—Influence of silicon on the corrosion resistance of 21 percent chromium, 15 percent nickel austenitic valve steel.

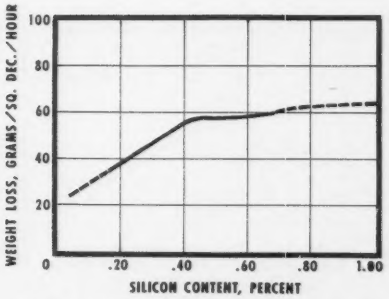


Figure 9—Influence of silicon on the corrosion resistance of 21 percent chromium, 15 percent manganese austenitic valve steel.

## Valve Alloys

All of the valve alloys in current use have been subjected to the lead corrosion test described above (See Figure 7). SAE-3140 steel is used frequently for intake valves in current engines and shows how a conventional low alloy steel reacts in this test. Silcrome #1 and Silcrome XB, alloys that were developed several years ago, contain appreciable percentages of chromium and silicon which were used to impart oxidation resistance to the steel. These materials enjoyed wide usage in engines prior to large scale use of tetraethyl lead and still find application in equipment where the design is such that the valve operates at moderate temperatures.

Silcrome XCR is a phase hardening steel that was developed to obtain optimum physical properties in the valve structure. This steel contains a nickel addition which contributes to its improved corrosion resistance. The 21-12N, Silcrome 10N and 21-4N are austenitic steels which are used to obtain high hot strength. Additional alloying elements, nickel and manganese, are used in these materials to obtain the austenitic structure and these materials contribute to the corrosion resistance. The TPM material is a nickel base alloy used for aircraft valves, in which nickel and chromium account for the bulk of the analysis.

It should be pointed out that with certain notable exceptions, none of these alloys was designed primarily for corrosion resistance. Because the valve is a highly stressed operating member in the engine, it is necessary that the material used possess unique physical properties at elevated temperatures. Consequently, a good deal of attention has been devoted to obtaining creep resistance, high hot fatigue strength and high hot hardness. The corrosion resistance of these alloys therefore represent something of a compromise. The exceptions mentioned above are the 21-4N and TPM alloys for which lead corrosion resistance was of paramount importance.

The detailed analyses of these various materials (Table 1) shows what was done to improve corrosion resistance. Higher alloy contents were used in the 21-4N and TPM than in the earlier analyses, a factor which contributed to the physical properties as well as to the corrosion resistance. It should be noted that the high silicon contents advocated in the early valve steels were reduced drastically in these two materials. It has been only recently that the effects of silicon as well as other low concentration elements have been fully recognized.

## Influence of Silicon

The influence of silicon in the typical 21 percent chromium, 15 percent nickel austenitic valve steel shows that relatively low concentrations of silicon can have a deleterious effect on the corrosion resistance (Figure 8). Silicon of 0.5 percent produces the most rapid corrosion of the steel whereas reductions in the silicon content drastically reduce the corrosion rate. Increasing the silicon concentration above 0.5 percent also reduces the corrosion rate, but to a lesser extent. The variation in corrosion rate with silicon above this concentration is small, however, and it is easy to appreciate why the true effects of silicon were not too well understood for many years.

Austenitic valve steels in which manganese was used in place of nickel have received a good deal of attention. The effect of silicon in these steels (Figure 9) is similar to that in the chromium-nickel steel. The authors did not have data for a sufficiently high silicon content to determine whether or not there is a maximum to the corrosion rate but it would appear there is a point of inflection in the curve at about 0.5 percent silicon. The relatively rapid change in corrosion rate with silicon concentration up to this value again shows that the optimum silicon for corrosion resistance should be very low.

In comparing the corrosion rates of the chromium-nickel and chromium-manganese steels, it would appear that nickel and manganese are interchangeable. Other experiments have shown that the effects of these two elements are additive, and that improvements in corrosion resistance can be attained by means of manganese additions up to about 10 percent to the chromium-nickel alloys. Because of factors relating to the processing of valve alloys and their physical properties, these chromium-nickel-manganese austen-

**TABLE 1—Analysis of Valve Steel Alloys**

| | C | Mn | Si | Cr | Ni | Fe | N2 | Other |
|---|---|---|---|---|---|---|---|---|
| 3140 | 0.4 | 0.8 | 0.3 | 0.7 | 1.3 | Bal | .... | ..... |
| XB | 0.8 | 0.4 | 2.0 | 21.0 | 1.5 | Bal | .... | ..... |
| Sil. 1 | 0.5 | 0.4 | 3.3 | 8.5 | .... | Bal | .... | ..... |
| XCR | 0.4 | 1.0 | 1.0 | 23.5 | 5.0 | Bal | .... | 2.8 Mo |
| Sil. 10 | 0.4 | 1.1 | 2.9 | 19.0 | 8.0 | Bal | .... | ..... |
| 21-12N | 0.2 | 1.3 | 1.0 | 21.0 | 11.5 | Bal | .18 | ..... |
| 21-4N | 0.5 | 9.0 | 0.2 | 21.0 | 4.0 | Bal | .40 | ..... |
| TPM | 0.1 | 2.0 | 0.1 | 15.7 | Bal | 6.0 | .... | 3 Ti |

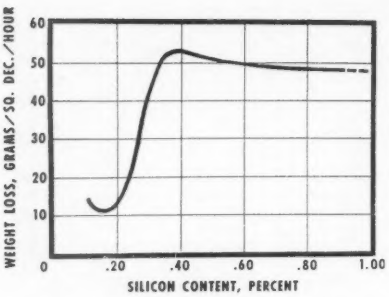


Figure 10—Influence of silicon on the corrosion resistance of 21 percent chromium, 3 percent nickel, 10 manganese austenitic valve steel.

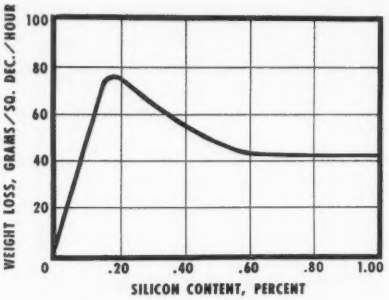


Figure 11—Influence of silicon on the corrosion resistance of 21 percent chromium, 4 percent nickel, 3 percent molybdenum austenitic valve steel.

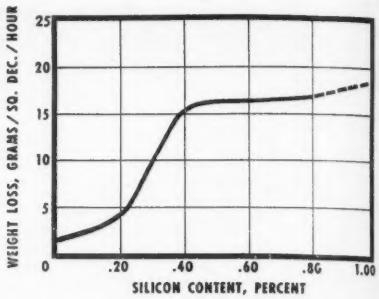


Figure 12—Influence of silicon on the corrosion resistance of 20 percent chromium, 15 percent nickel, 15 percent cobalt austenitic valve steel.

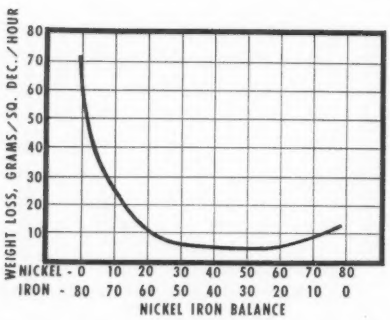


Figure 13—The effect of nickel-iron balance on the corrosion resistance of alloy steels containing 20 percent chromium and .15 percent carbon.

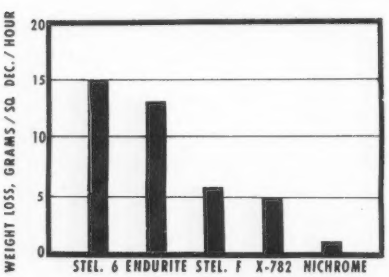


Figure 14—Corrosion resistance of conventional valve facing alloys.

itic steels appear to be optimum. The effect of silicon in such steels is similar to that for the chromium-nickel and chromium-manganese alloys (Figure 10) and low silicon contents are desirable for best corrosion properties.

Chromium-nickel-molybdenum (Figure 11) and chromium-nickel-cobalt (Figure 12) alloys have been investigated, although the latter has not achieved commercial importance. While molybdenum is a valuable strengthening agent it has a tendency to oxidize in high concentrations. The objection to cobalt is purely an economic one inasmuch as cobalt has a pronounced effect in reducing the corrosion rate.

**TABLE 2—Analysis of Valve Facing Alloys**

| | C | Mn | Si | Fe | Cr | Ni | W | Co |
|---|---|---|---|---|---|---|---|---|
| Stellite 6 | 1.05 | .06 | 1.21 | 2.0 | 27.6 | .... | 4.25 | Bal |
| Stellite F | 1.6 | .25 | 1.25 | .... | 24.0 | 24.0 | 12.5 | 37.0 |
| X-782 | 2.0 | .... | .... | 4.0 | 25.0 | 60.0 | 8.5 | .... |
| Endurite | 2.0 | .... | 1.0 | 8.0 | 29.0 | 39.0 | 13.15 | 10.0 |
| Nichrome | 0.2 | .94 | .21 | .80 | 20.25 | 77.1 | .... | .... |

## Aircraft Valves

The nickel-base alloys are rapidly replacing the alloy steels in aircraft valve applications. In developing these alloys, variations in the nickel-iron content were investigated (See Figure 13). The results show that nickel is effective in reducing the corrosion rate up to very high concentrations. Some increase in corrosion appears to take place with nickel concentrations over 60 percent, but this may have been caused by variations in the impurities. These data were obtained before the effects of silicon, aluminum, manganese and titanium were fully recognized. Later work showed that silicon and aluminum both had a deleterious effect. Manganese up to about 3 percent improved the corrosion resistance, and titanium also caused some improvement.

The TPM alloy currently used for aircraft valves is comprised of 16 percent chromium, 6 percent iron, 3 percent titanium and 2 percent manganese with nickel making up the 73 percent balance. Silicon and aluminum both are held to low limits. This alloy has given a very creditable account of itself, and in one engine model reduced valve failures by a factor of seven.

A type of valve construction frequently employed for heavy duty engines incorporates a seat of welded material puddled on the valve face. In this way optimum corrosion and hardness properties for the valve seating surface can be obtained. Special alloys have been developed for this purpose (See Table 2). These alloys all have high chromium, cobalt and nickel contents to enable them to achieve corrosion resistance; Tungsten is used there primarily as a hardening agent. The corrosion resistance of these materials is uniformly good (See Figure 14) and superior to that of all commercial valve steels except TPM.

The alloy known as X-782 is used to coat the seats and heads of some aircraft valves made from TPM. This coating imparts additional pitting resistance to the valve, even though the laboratory test indicates that TPM is more corrosion resistant than X-782.

### Valve Rotators

It should be pointed out that there are ways to reduce exhaust valve corrosion other than simply by controlling the material analysis. One of the most significant developments in this respect has been the widespread use of valve rotators. These devices cause the valve to turn, and function by knocking off the deposits that form on the valve stem and face. This action improves the gas seal, lowers the valve temperature and thus retards valve corrosion (See Figure 15). When these devices were used engine tests consistently showed valve life improvements of from two to five times. Because of this it is not surprising that most heavy duty engines today use valve rotation of one form or another.

Another recent development is the use of protective coatings. In the General Motors Al-Dip process, a coating of pure aluminum is applied to the valve by means of a hot dip or metallizing process. The aluminum reacts with the iron in the valve steel to form a complex compound that is extremely corrosion resistant. Engine tests with this coating on XCR valve steel (See Figure 16) have shown improvement in valve life of from two to four times.

Much still can be accomplished in reducing exhaust valve corrosion. Although steels of conventional forging analyses have been fairly well explored, new processing techniques offer considerable promise. Vacuum melting is being investigated, and early results indicate that improved corrosion resistance can be obtained by this method. The casting of valves offers another alternative. By this method, highly alloyed materials impractical for forging can be handled. Composite valves of various materials and protective coatings also are being investigated further.

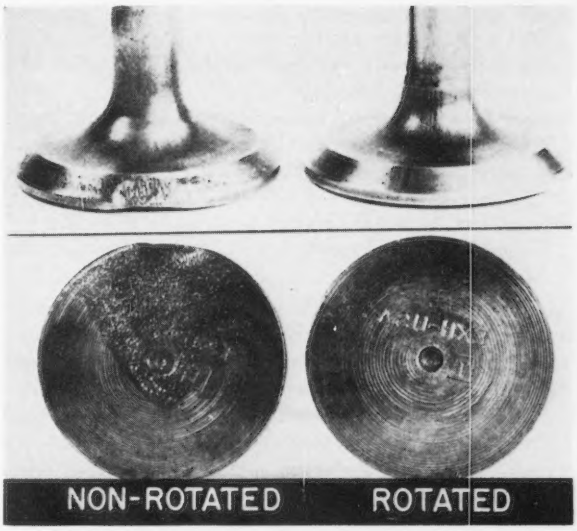


Figure 15—Comparison of rotated and non-rotated valves.

Figure 16—Corrosion of uncoated and aluminum coated valves.

### Acknowledgment

The authors acknowledge the assistance of P. A. Jennings in the preparation of this paper and thank him for the use of his data.

## DISCUSSION

**Question by Thomas L. Hoffman, Phillips Petroleum Company, Idaho Falls, Idaho:**

It surprises me to learn your reaction concerning aluminum coated valves. These data appear to be inconsistent with the tables published in W. D. Manly's Chicago conference paper "Corrosion of Materials in Sodium, Lithium and Lead." The Manly paper indicates that aluminum is one of the poorest alloys for molten lead service.

**Reply by C. H. Allen:**

In the case of aluminum coated exhaust valves we are not concerned with corrosion resistance under continuous exposure to molten lead, but rather with corrosion resistance to the products of combustion of leaded gasoline.

The molten lead oxide test described in the paper has served very well as an indicator to determine the probable service life of a valve alloy but it is not infallible. A lead oxide test performed on an aluminum coated specimen would indicate very poor corrosion resistance.

It is suspected that the benefit of aluminum coating on exhaust valves lies in the aluminum-iron alloy that forms at the interface rather than the pure aluminum outer coating. Also, this coating tends to prevent deposits from sticking to the exhaust valve face.

**Questions by Nicholas P. Harvey, Brooklyn, N. Y.:**

1. With respect to the Al-Dip process for protection are you using both dipping and metal spraying for applying aluminum?

2. In line with the above question do you find the coatings comparable in continuity, evenness, etc.?

We are interested in a comparison of the quality of coatings obtained by dipping and metal spraying with molten salt after treatment; also in the thickness and uniformity of coatings.

**Replies by C. H. Allen:**

1. We have used both techniques in production. We have now replaced the dipping method with the metal spray technique.

2. The metal spray method provides a more even

distribution of aluminum over the valve head contour. It was necessary to remove excess aluminum from the valve face with an air blast in the dip method and this did not prove entirely satisfactory. The air blast cleaning has been eliminated in the metal spray method and a much better looking and more continuous aluminum coating has resulted.

**Discussion by S. D. Heron and Robert V. Kerley, Ethyl Corporation Research Laboratories, Detroit, Michigan:**

The authors have presented a very fair and well-balanced discussion of the problem of corrosion of valve materials by the combustion products of fuels containing a lead antiknock compound.

The scope of a discussion of lead corrosion of valve steels must be limited and the authors have, possibly wisely, restricted theirs mostly to a comparison of valve steels in laboratory crucible tests. However, the Ethyl Research Laboratories consider that the problem is unfortunately much more complex than as stated by the authors.

If materials could be rated by the simple procedure of testing them for their resistance to lead oxide, the problem would be vastly simpler than it is in our experience. While the authors point out that the lead oxide test must be supported by engine tests, they nevertheless leave the impression that they rely on it to a much greater extent than we consider to be sound. For instance, we consider that the relative lead oxide rating of Stellite No. 6 and Nichrome is quite misleading as regards engine use. The authors, to some extent, support this view by their remarks on the relative performance of X782 and TPM.

It is believed that the Ethyl Corporation were the first to use laboratory methods of testing engine materials for resistance to corrosion by lead compounds. The work involved the use of lead bromide and was carried out about 1930 for the United States Army Air Force. This work was extremely valuable to the Air Force and showed that aluminum-bronze for valve seat inserts and mild steel for exhaust manifolds were very poor materials. The findings confirmed existing knowledge that aluminum-bronze was much inferior to austenitic nickel-chromium steel for valve seat inserts and directly led the Air Force into the use of 18 Cr 8 Ni steel for exhaust manifolds.

Subsequent to the Ethyl Corporation work, the Air Force carried on an investigation of a variety of laboratory corrosion test methods which were helpful but not conclusive. For example, it was an engine test and not a laboratory corrosion test which showed the value of Stellite No. 6 for facing exhaust valves. About 1934 the Ethyl Corporation resumed corrosion studies which were carried on continuously until about 1950. These studies involved three furnaces which exposed specimens to flames produced by burning leaded fuels. In one furnace scaling tests only were carried out. In the other two furnaces stress rupture tests involving more than one-quarter million specimen test hours were carried out.

About 1950 the Ethyl Corporation regretfully came to the conclusion that none of the laboratory tests were adequate for appraising exhaust valve materials and that it would be necessary to rely on engine tests. This conclusion was arrived at despite the fact that laboratory corrosion tests had involved lead oxide, lead bromide, lead chloride, lead sulfate, lead phosphate and mixtures of these compounds.

While the engine test is now regarded as the conclusive answer, it has not simplified the problem since valve materials may change their relative ratings depending upon the sulfur content of the gasoline used and upon whether or not fuel additives are used. The additive type and its concentration can have marked effects; an additive may improve valve life or may very sharply reduce it. A given additive may have no effect upon valve corrosion at low valve temperature and may increase the rate of weight loss by one thousand per cent at high valve temperature. Felt, Kerley and Sumner[1] have extensively discussed the problem of additives and their effects upon exhaust valve life.

We believe that Hives and Smith[2] in 1939 were the first to propose the simple lead oxide test for appraising the corrosion resistance of exhaust valve materials. We could not accept the proposal as sound at that time and still cannot do so.

It would be unfair to indicate that the corrosion resistance of valve steels to lead oxide cannot be correctly rated in laboratory crucibles. It is our opinion, however, that the rating obtained may bear no relation either to the amount of corrosion (valve weight loss) actually experienced when the material is used as an exhaust valve or to the life of the exhaust valve as measured by miles until it is burned. In addition to lead, oxygen, bromine, chlorine and sulfur, exhaust valve deposits may include barium, phosphorous, boron, silicon and other materials which currently are present in the fuel, oil, or air breathed by the engine. It is not necessary that the material found in the deposit actually corrode the valve steel in order for it to markedly affect valve life.

It is indicated that the physical nature of the deposit —its ease of channelling, for example—may be very important since this channelling may result in exposure of the valve face to high temperature, thereby leading to burning. In vehicle tests which have been conducted by the Ethyl Research Laboratories (See Figure 17) it was found, for example, that valve material "A" resulted in an average life of 31,700 miles in passenger car Make Q-2 as compared to an average life of over 77,000 miles for valve material "B". This comparison was obtained with a fuel containing very low (.003 percent) sulfur. When a higher sulfur fuel (.07 percent) was used in the same vehicles, valve materials "A" and "B" were found to give essentially equal valve life of 25,000 miles.

In the same fleet of passenger cars, Make F-2 using valve material "B", averaged 11,800 miles to valve failure on the low sulfur fuel as compared to 77,000 miles to valve failure for a passenger car Make Q-2 which used valve material "B". When fuel containing

(1) A. E. Felt, R. V. Kerley and H. C. Sumner. Fuel Additives and Engine Durability. Presented at SAE National West Coast Meeting, Los Angeles, California, August, 1954.

(2) E. W. Hives and L. Smith. High-Output Aircraft Engines. *SAE Transactions*, **46**, No. 3, 106-117, 1940 (March).

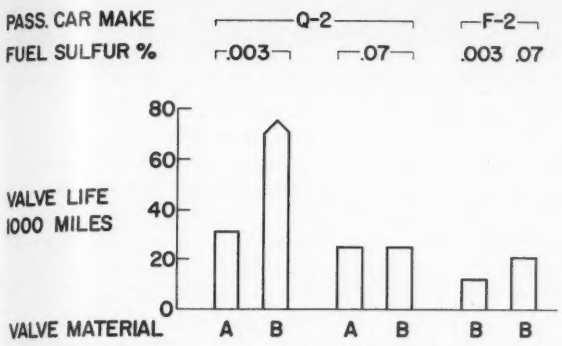


Figure 17—Base fuel effect on valve life.

the higher sulfur content was used in the same fleet and with the same valve materials, vehicle Make F-2 increased to an average valve life of 21,000 miles while vehicle Make Q-2 dropped to 25,000 miles.

It would appear impossible for laboratory crucible tests to have predicted this valve life change. It seems more likely that physical nature of deposits at the operating temperatures existing on the valves and seats of the particular engines was responsible for the reversals of relative valve life which were experienced.

**Reply by C. H. Allen:**

It is perhaps unfortunate that this paper was necessarily confined to a discussion of *corrosion* of exhaust valve alloys. It is sincerely appreciated by the authors that corrosion does not of itself describe the compatibility of a given alloy to operation in a gasoline fueled internal combustion engine.

Many other high temperature properties such as yield strength, erosion resistance and abrasion resistance determine the value of an exhaust valve alloy. In some cases corrosion resistance plays a relatively minor part.

The lead oxide corrosion test is used only as a screening test in the early stages of alloy development. In all cases, actual engine tests must be conducted before such alloys can be declared acceptable. In general, however, a material which does not possess good oxide corrosion resistance, even though it possesses other desirable properties, is unsuitable as an exhaust valve alloy unless it is protected by a coating material.

**Discussion by Paul A. Jennings, Armco Research Laboratories, Baltimore, Maryland:**

An exhaust valve to function properly in an internal combustion engine must possess two important characteristics: (1) valve design as related to size, shape and mass, and (2) metallurgical factors as related to chemical composition and microstructure.

As mentioned previously by the authors, an exhaust valve must possess good resistance to attack by lead oxide, good hot hardness in the head section, good stretch resistance, good wear resistance and good stem and tip hardness. Inasmuch as this paper discusses only the corrosion aspects desired in exhaust valves, the other necessary requirements just enumerated will not be discussed further.

In the development of an improved exhaust valve

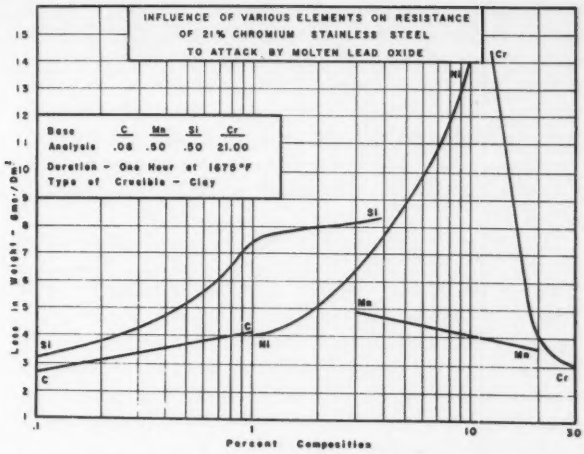
INFLUENCE OF VARIOUS ELEMENTS ON RESISTANCE OF 21% CHROMIUM STAINLESS STEEL TO ATTACK BY MOLTEN LEAD OXIDE
Base Analysis C .08 Mn .50 Si .50 Cr 21.00
Duration - One Hour at 1675°F
Type of Crucible - Clay
Loss in Weight - Gms./Dm²
Percent Composition

Figure 18—Influence of carbon, manganese, silicon, chromium and nickel on 21 percent chromium stainless steel to attack by molten lead oxide.

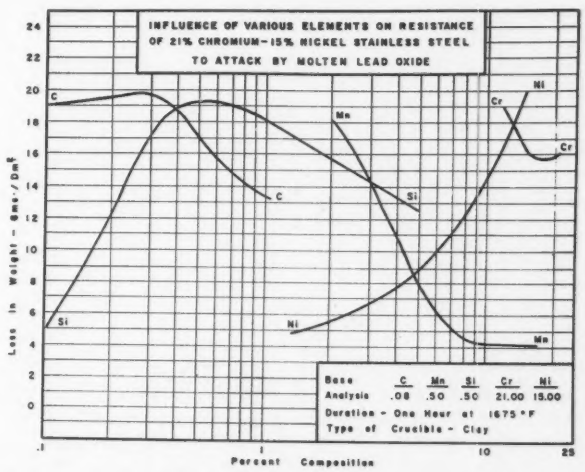
INFLUENCE OF VARIOUS ELEMENTS ON RESISTANCE OF 21% CHROMIUM-15% NICKEL STAINLESS STEEL TO ATTACK BY MOLTEN LEAD OXIDE
Base Analysis C .08 Mn .50 Si .50 Cr 21.00 Ni 15.00
Duration - One Hour at 1675°F
Type of Crucible - Clay
Loss in Weight - Gms./Dm²
Percent Composition

Figure 19—Influence of various elements on resistance of 21 percent chromium—15 percent nickel stainless steel to attack by molten lead oxide.

material considerable emphasis was placed on the need for a material which had much better resistance to attack by lead oxide than the stainless steel alloys currently being used for the manufacture of exhaust valves.

In order to resolve the problem of improved lead oxide resistance, we approached the problem by making two basic compositions. One was a ferritic 21 percent chromium stainless steel alloy, while the other was an austenitic 21 percent chromium-15 percent nickel stainless steel alloy. To each of these compositions one element at a time was added to the base composition on a percentage by weight basis. The total number of elements investigated using this procedure was 23. Because of space limitations the influence of only the more important elements will be discussed.

To show the influence of some of the more important elements when added to these two base compositions, two illustrations have been prepared.

Figure 18 shows the influence of carbon, manganese, silicon, chromium and nickel with respect to lead cor-

rosion when added to the ferritic 21 percent chromium stainless steel base composition. To depict the influence of these elements with respect to lead oxide corrosion loss on a single chart, a semi-log plot was needed. When a logarithmic scale was used the abscissa axis showed the percent composition and when a linear scale was used the ordinate axis showed the loss in weight expressed as grams per square decimeter.

It should be pointed out that the lead oxide value for the ferritic 21 percent chromium base composition before any given element had been added was 4 grams/square decimeter loss in weight. Thus, it can be seen that silicon greater than .25 percent, nickel greater than 1 percent, chromium less than 20 percent, carbon greater than .80 percent and manganese less than 10 percent all adversely affect lead oxide resistance of the base composition.

Figure 19 shows the influence of carbon, manganese, silicon, chromium and nickel with respect to lead corrosion when added to the austenitic 21 percent chromium-15 percent nickel base composition. Again the data are depicted on a similar plot.

In this second case, however, the lead oxide value for the austenitic 21 percent chromium-15 percent nickel base composition before any given element had been added was 18 grams/square decimeter loss in weight. Thus it can be seen that carbon less than .45 percent, nickel greater than 15 percent, chromium less than 15 percent and silicon in the range of about .33 to 1.0 percent all adversely affect lead oxide resistance of the base composition. Manganese reduces lead oxide attack for all quantities studied in the range of 2 to 17 percent. It may be noted, however, that there is no particular advantage in adding manganese to the base composition above approximately 10 percent.

***Any discussions of this article not published above will appear in the June, 1956 issue.***

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Publication 56-1

*A Report of Technical Unit Committee T-2B on Anodes for Impressed Current* ★

# Final Report on Four Annual Anode Inspections

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★ T. J. Maitland, American Telephone and Telegraph Co., New York City, chairman.


## Abstract

Four test ground beds were installed so that comparative data could be obtained concerning the performance of steel anodes in natural soil, carbon and graphite anodes in natural soil, carbon and graphite anodes in carbonaceous backfill, and steel anodes in carbonaceous backfill. Representative anodes were inspected at one year intervals with the final inspection coming four years after the beds were set up.

Of the anode types tested it was found that graphite anodes in a carbonaceous backfill gave the best results. Recommendations were made concerning the installation of anodes, the selection of ground bed sites and the use of various backfills.


## 1.0 General

THIS IS A REPORT on findings of the fourth and final annual inspection of ground anodes taken from four test ground beds installed by the Mississippi Power and Light Company under an anode-comparison field test program sponsored by this committee. The ground beds, with an original total of 60 anodes, were operated with impressed current under close control by engineers of the Mississippi Power and Light Company Gas Department (now Mississippi Valley Gas Company). Complete operating data were taken monthly. These data were furnished to the committee for analysis and in addition, one-quarter of the anodes were removed from each bed each year throughout the four-year test program in order to determine the extent of deterioration. The test results, conclusions, and recommendations contained in this report pertain to anode types as tested in soils only and do not cover installations in fresh water, salt water or other conducting solutions.

The Mississippi test beds were so arranged that comparative data could be procured concerning the performance of carbon and graphite anodes in natural soil, steel anodes in natural soil, carbon and graphite anodes in carbonaceous backfill, and steel anodes in carbonaceous backfill. Details concerning ground bed construction are included in the first annual report prepared by the committee and published as NACE publication 50-1, "First Interim Report on Ground Anode Tests of Technical Prac-

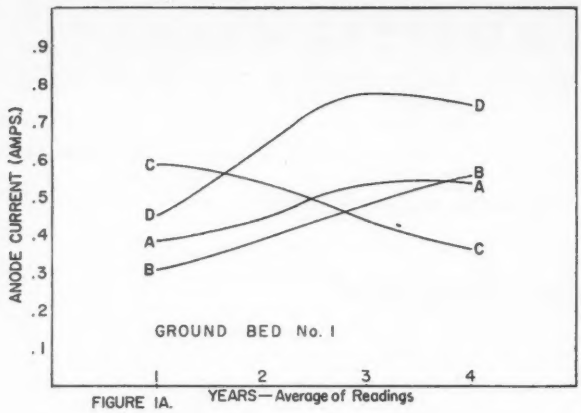


FIGURE 1A.

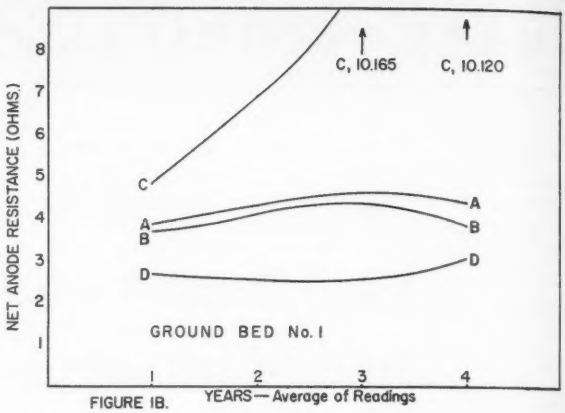


FIGURE 1B.

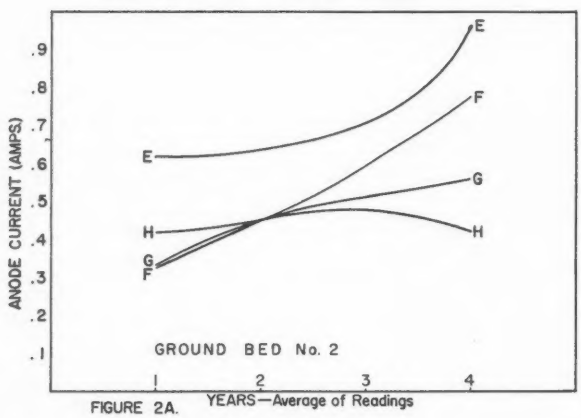


FIGURE 2A.

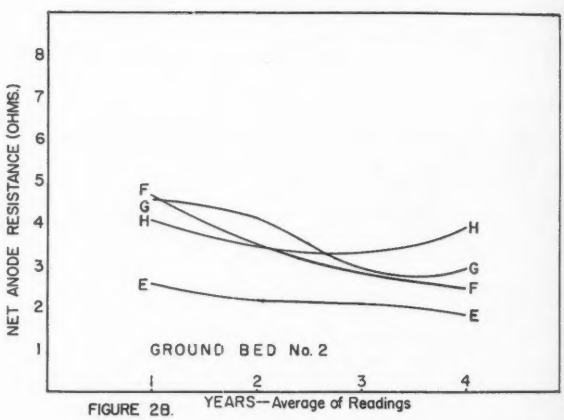


FIGURE 2B.

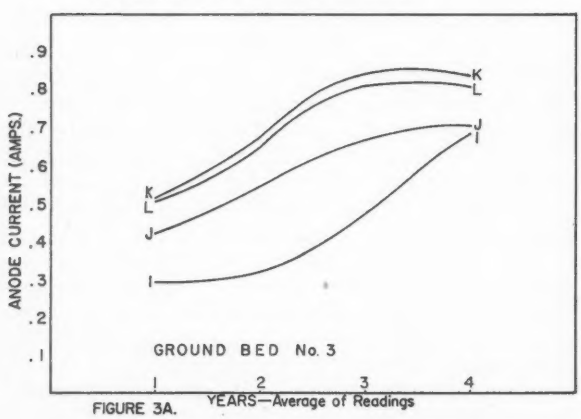


FIGURE 3A.

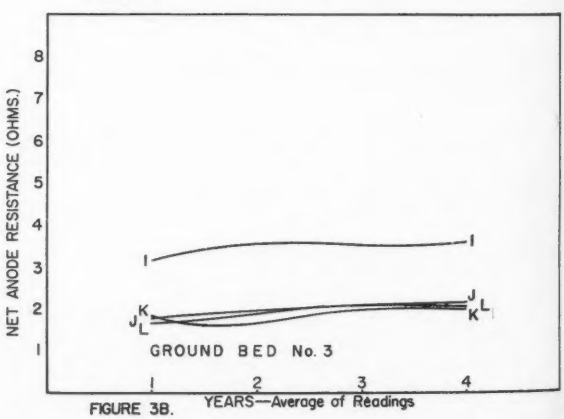


FIGURE 3B.

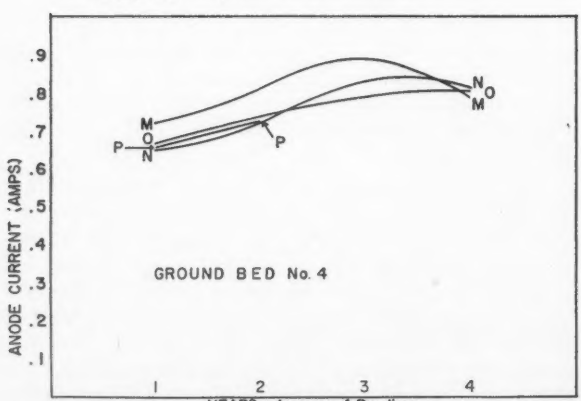


FIGURE 4A.

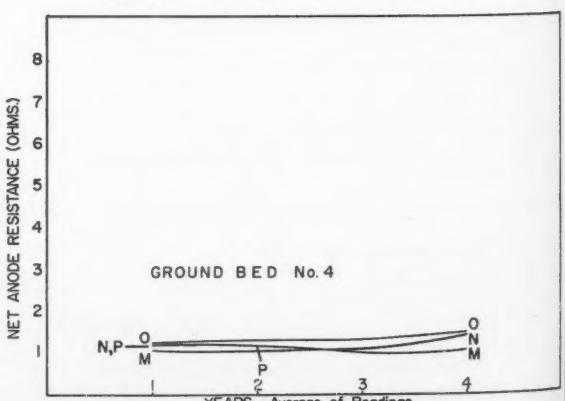


FIGURE 4B.

**TABLE 1—Summary of Data for Ground Bed No. 1**

| Anode Material* and Backfill | Anode Current (Amps) | Net Anode Resistance (Ohms) |
|---|---|---|
| **A. Anodes 1, 5, 9, 13: Carbon in natural soil backfill** | | |
| Four anodes for one year (average of 48 readings) | .382 | 3.894 |
| Three anodes for two years (average of 72 readings) | .444 | 4.300 |
| Two anodes for three years (average of 72 readings) | .534 | 4.647 |
| One anode for four years (average of 48 readings) | .530 | 4.410 |
| **B. Anodes, 2, 6, 10, 14: Graphite in natural soil backfill** | | |
| Four anodes for one year (average of 48 readings) | .310 | 3.707 |
| Three anodes for two years (average of 72 readings) | .389 | 4.156 |
| Two anodes for three years (average of 72 readings) | .477 | 4.424 |
| One anode for four years (average of 48 readings) | .555 | 3.845 |
| **C. Anodes 3, 7, 11, 15: Steel in natural soil backfill** | | |
| Four anodes for one year (average of 48 readings) | .588 | 4.844 |
| Three anodes for two years (average of 72 readings) | .540 | 6.951 |
| Two anodes for three years (average of 72 readings) | .443 | 10.165 |
| One anode for four years (average of 48 readings) | .366 | 10.120 |
| **D. Anodes 4, 8, 12, 16: Graphite in natural soil and gypsum** | | |
| Four anodes for one year (average of 48 readings) | .459 | 2.734 |
| Three anodes for two years (average of 72 readings) | .631 | 2.685 |
| Two anodes for three years (average of 72 readings) | .775 | 2.657 |
| One anode for four years (average of 48 readings) | .745 | 3.040 |

* All anodes 4 inches x 80 inches.

**TABLE 2—Summary of Data for Ground Bed No. 2**

| Anode Material* and Backfill | Anode Current (Amps) | Net Anode Resistance (Ohms) |
|---|---|---|
| **E. Anodes 1, 5, 9, 13: Graphite in coke breeze backfill** | | |
| Four anodes for one year (average of 48 readings) | .618 | 2.613 |
| Three anodes for two years (average of 72 readings) | .642 | 2.187 |
| Two anodes for three years (average of 72 readings) | .709 | 2.115 |
| One anode for four years (average of 48 readings) | .966 | 1.835 |
| **F. Anodes 2, 6, 10, 14: Graphite in graphite backfill** | | |
| Four anodes for one year (average of 48 readings) | .328 | 4.735 |
| Three anodes for two years (average of 72 readings) | .455 | 3.543 |
| Two anodes for three years (average of 72 readings) | .594 | 2.851 |
| One anode for four years (average of 48 readings) | .776 | 2.495 |
| **G. Anodes 3, 7, 11, 15: Graphite in graphite and lime backfill** | | |
| Four anodes for one year (average of 48 readings) | .329 | 4.636 |
| Three anodes for two years (average of 72 readings) | .457 | 4.169 |
| Two anodes for three years (average of 72 readings) | .519 | 2.937 |
| One anode for four years (average of 48 readings) | .566 | 2.801 |
| **H. Anodes 4, 8, 12, 16: Steel pipe in coke breeze backfill** | | |
| Four anodes for one year (average of 48 readings) | .423 | 4.053 |
| Three anodes for two years (average of 72 readings) | .450 | 3.488 |
| Two anodes for three years (average of 72 readings) | .477 | 3.313 |
| One anode for four years (average of 48 readings) | .429 | 3.914 |

* All anodes 2 inches x 80 inches.

tices Committee No. 3—Anodes for Impressed Current."[1]

Accumulated operating data are contained in the first, second and third annual reports which contain details of the condition of anodes which had been in operation from one to three years. These reports are in the committee files. Results reported in the first annual report are summarized in Publication 50-1. The second and third annual reports were not published separately, but the results reported are summarized herein.

## 2.0 Discussion of Results of Four-Year Program

The results of the four-year program have given positive indications of relative anode performance with some types giving excellent service throughout the test period and others showing highly advanced deterioration within the four years. This variation in performance has been great enough to permit reasonably conclusive deductions concerning anode performance under installation conditions as encountered in Mississippi. (See Tables 1 through 4 and Figures 1 through 4.)

### 2.1 *Carbon and Graphite Anodes in Natural Soil*

A total of 16 carbon and graphite anodes were installed (including 4 which were backfilled with a mixture of natural soil and gypsum). The anodes measured 4 inches x 80 inches. In all cases, these anodes showed visual evidence of attack when removed for inspection with the extent of attack progressively greater after each year of service. Attack usually was evidenced by the rounding off of the lower ends of the anodes with surface softening of the remaining material. Softening was evident to depths of up to 1 inch at the lower ends (after 4 years) with softening to lesser depths on upper portions of the anodes.

In some cases, softening was relatively severe at localized areas (possibly due to lower resistivity inclusions in the backfill) which tended to cause depressions in the anodes. In other cases, there was heavy attack just below the impregnation at the lead end of the anodes.

It has been estimated that the life of these 4-inch

**TABLE 3—Summary of Data for Ground Bed No. 3**

| Anode Material and Backfill | Anode Current (Amps) | Net Anode Resistance (Ohms) |
|---|---|---|
| **I. Anodes 1, 5, 9, 13: Graphite in natural soil (Anodes 4 inches x 80 inches)** | | |
| Four anodes for one year (average of 48 readings) | .293 | 3.192 |
| Three anodes for two years (average of 72 readings) | .322 | 3.528 |
| Two anodes for three years (average of 72 readings) | .475 | 3.577 |
| One anode for four years (average of 48 readings) | .682 | 3.600 |
| **J. Anodes 2, 6, 10, 14: Steel in coke breeze (Anodes 2 inches x 80 inches)** | | |
| Four anodes for one year (average of 48 readings) | .423 | 1.764 |
| Three anodes for two years (average of 72 readings) | .549 | 1.964 |
| Two anodes for three years (average of 72 readings) | .671 | 2.084 |
| One anode for four years (average of 48 readings) | .706 | 2.171 |
| **K. Anodes 3, 7, 11, 15: Graphite in coke breeze and lime (Anodes 2 inches x 80 inches)** | | |
| Four anodes for one year (average of 48 readings) | .523 | 1.795 |
| Three anodes for two years (average of 72 readings) | .670 | 1.697 |
| Two anodes for three years (average of 72 readings) | .852 | 1.987 |
| One anode for four years (average of 48 readings) | .830 | 1.989 |
| **L. Anodes 4, 8, 12, 16: Graphite in graphite (Anodes 2 inches x 80 inches)** | | |
| Four anodes for one year (average of 48 readings) | .515 | 1.648 |
| Three anodes for two years (average of 72 readings) | .656 | 1.859 |
| Two anodes for three years (average of 72 readings) | .814 | 2.089 |
| One anode for four years (average of 48 readings) | .802 | 2.053 |

**TABLE 4—Summary of Data for Ground Bed No. 4**

| Anode Material and Backfill | Anode Current (Amps) | Net Anode Resistance (Ohms) |
|---|---|---|
| **M. Anodes 1, 4, 7, 11: Graphite in coke breeze (Anodes 2 inches x 80 inches)** | | |
| Four anodes for one year (average of 48 readings) | .720 | 1.088 |
| Three anodes for two years (average of 72 readings) | .811 | 1.080 |
| Two anodes for three years (average of 72 readings) | .899 | 1.158 |
| One anode for four years (average of 48 readings) | .786 | 1.386 |
| **N. Anodes 2, 5, 8, 9: Graphite in coke breeze column (Anodes 4 inches x 20 inches)** | | |
| Four anodes for one year (average of 48 readings) | .653 | 1.130 |
| Three anodes for two years (average of 72 readings) | .723 | 1.139 |
| Two anodes for three years (average of 72 readings) | .836 | 1.071 |
| One anode for four years (average of 48 readings) | .816 | 1.095 |
| **O. Anodes 3, 10, 12: Carbon in coke breeze (Anodes 2 inches x 80 inches)** | | |
| Three anodes for one year (average of 36 readings) | .667 | 1.242 |
| Two anodes for two years (average of 48 readings) | .729 | 1.323 |
| Two anodes for three years (average of 72 readings) | .790 | 1.393 |
| One anode for four years (average of 48 readings) | .806 | 1.418 |
| **P. Anode 6: Carbon in coke breeze (Anode 2 inches x 45 inches)** | | |
| First year (average of 12 readings) | .659 | 1.152 |
| Second year (average of 24 readings) | .749 | 1.138 |

[1] Available from NACE, 1061 M & M Building, Houston 2, Texas.

x 80-inch carbon and graphite anodes in natural soil as installed in the Mississippi beds would be between 10 and 15 years with impressed currents of less than one ampere per anode.

Where 4-inch x 80-inch graphite anodes in natural soil were in the same ground bed with 2-inch x 80-inch graphite anodes in carbonaceous backfill (Ground Bed No. 3), the anodes in natural soil had higher resistance to earth than those in carbonaceous backfill and hence did not have as great a current output.

### 2.2 *Steel Anodes in Natural Soil*

A total of four 4-inch x 80-inch anodes of steel pipe were installed in natural soil backfill. The test data taken on these anodes have revealed that steel in natural soil is not necessarily consumed at the full theoretical rate of 20 pounds per ampere per year. Actually, the tabulated data indicated the anodes were consumed at rates ranging from 79.2 percent to 110 percent of theoretical with an average of approximately 93 percent. Limitations in accuracy of test data based on monthly readings may possibly account for data indicating that two of the four anodes corroded at greater than the theoretical rate.

It was interesting to note that the resistance to soil of steel anodes was greater than the resistance to soil of carbon or graphite anodes (without carbonaceous backfill) in the same ground bed. (See Table 1 and Figure 1.) The difference in resistance was so great that the steel anodes discharged less current than the carbon or graphite anodes even though the latter have an appreciable back voltage which must be overcome by the impressed current supply.

### 2.3 *Carbon and Graphite Anodes in Carbonaceous Backfill*

Twenty-nine 2-inch x 80-inch carbon and graphite anodes and three 4-inch x 20-inch graphite anodes were installed in a carbonaceous backfill; they all have been removed for inspection except for two 2-inch x 80-inch anodes which were covered with a concrete drive after one ground bed was installed. Of the 30 anodes inspected, all but three showed no appreciable evidence of attack and apparently were in nearly the same condition as when installed.

Of the three anodes which were attacked (after 4 years service), one was softened to a depth of 1/16-inch on the bottom end but with no loss of material and another was softened to a depth of 1/8-inch for 1½ inches on the bottom end with slight rounding of the edges at the bottom. The remaining anode was soft throughout the bottom 24-inches with maximum softening (to a depth of ½-inch) at the lower end and some material loss due to slight tapering at the bottom 6 inches of the anode. Inasmuch as this last described anode was the only one seriously attacked while a large number showed little evidence of attack, it is felt that in this particular case the carbonaceous backfill may not have extended to the bottom of the hole due to caving in of the sides of the hole at the time of installation (also see Section 4.3).

Graphite or carbon anodes in carbonaceous backfill were found to have consistently lower resistance to earth than any of the other types of anode installation tested in these ground beds.

No estimate could be made concerning the probable life of carbon and graphite in carbonaceous backfills because of the absence of any attack on the anode core in the great majority of cases. Life probably will depend on consumption of the backfill material although there was little evidence of backfill consumption during the four-year test period.

### 2.4 *Steel Anodes in Carbonaceous Backfill*

Eight anodes consisting of 2-inch x 80-inch steel pipe in coke breeze backfill were installed. Performance of this type of installation was inconsistent in that the rate of consumption of the steel core was found to vary greatly even though in all cases it was less than 100 percent of the theoretical rate for iron. The range observed during the four years was from 7.3 to 76.2 percent of the theoretical rate. There was a significant tendency for the rate of consumption to reduce with age of the anode as follows:

End of 1 year, average for 2 anodes: 56 percent
End of 2 years, average for 2 anodes: 32 percent
End of 3 years, average for 2 anodes: 23 percent
End of 4 years, average for 2 anodes: 32 percent[2]

This tendency may be the result of a build-up of an iron oxide film which tends to act as an oxygen anode. This tendency was greater at one of the two beds containing this type of installation than it was at the other, indicating that soil environment was a factor. At Ground Bed No. 2 the 2-inch x 80-inch steel pipe cores apparently had a useful life of only about five years at an average current output of less than one ampere while at Ground Bed No. 3, the indicated life was more in the order of 20 years at current outputs comparable to those measured at Ground Bed No. 2.

The resistance to earth of the steel anodes in coke breeze was consistently greater than that of carbon or graphite anodes of the same size in carbonaceous backfills in the same ground beds.

## 3.0 Fourth Annual Inspection of Anodes at Ground Bed No. 1[3]

### 3.1 *Installation and Removal Data*

The sixteen anodes in Ground Bed No. 1 (located on Sunflower Street in Greenville, Miss.) were installed on February 25 and 26, 1947. Anodes 1, 2, 3 and 4 were removed after 341 days of operation and were not replaced. Anodes 13, 14, 15 and 16 were removed after 712 days of operation and were not replaced. Anodes 5, 6, 7 and 12 were removed after 1104 days of operation and replaced with three new

[2] As discussed in Section 4.3, evidence indicates that part of the steel anode in coke breeze removed (at the end of four years) at Ground Bed No. 2 was left in the anode hole so that the measured weight loss for this anode was greater than the actual weight of metal consumed. If properly allowed for, this could result in an average consumption rate at the end of four years which would be low enough to indicate a continuous reduction in corrosion rate with time.

[3] Summary performance curves and data may be found in Table 1 and Figure 1.

2-inch x 80-inch graphite anodes. On March 27, 1951, after 1489 days of operation, the remaining four anodes were removed and replaced with new 2-inch x 80-inch graphite anodes.

### 3.2 *Inspection Data—March 27, 1951—Fourth and Final Inspection*

The anode types listed in Table 5 were inspected. Information obtained at time of removal for these anodes is given in Table 6.

### 3.3 *Discussion of Inspection Data*

Accurate weight loss on the graphite and carbon anodes was not considered practical because of unknown original weight and moisture content. Of the two graphite anodes, Anode No. 8 (in natural soil and gypsum) was reduced in length more than Anode No. 10 (in natural soil only). Making liberal allowances for material removal on Anode No. 8 (2-inch loss in length, end rounded, and tapered ½-inch on lower 3 feet of remaining material), consumed graphite approximated 40.4 cubic inches. At a density of 0.0561 pound/cubic inch for graphite, loss in weight would be approximately 2.27 pounds. At an electrochemical equivalent of two pounds per ampere per year and with a total power consumption of 22,212 ampere hours, maximum theoretical loss would be 5.05 pounds. Actual loss was not more than 45 percent of theoretical.

Greatest loss of material was apparent on Anode No. 9 (carbon in natural soil). There was a 3½-inch loss in length, the end was rounded, and there was a ½-inch taper on the lower 3 feet of remaining anode; the amount of carbon consumed approximated 69.3 cubic inches. At a density of 0.0555 pound/cubic inch for carbon, loss in weight would be approximately 3.85 pounds. Using a theoretical rate of two pounds per ampere per year, the power consumption of 18,082 ampere hours would result in a weight loss of 4.13 pounds. The calculated loss would then be 93.3 percent of the theoretical loss.

The graphite anode in natural soil only gave the best performance in this group with least loss in weight (estimated to have been 40 percent or less of the weight loss on the carbon anode).

The steel anode had a measured weight loss of 23 pounds. The theoretical loss for a power consumption of 12,702 ampere hours would be 29 pounds. Actual loss was approximately 79.2 percent of theoretical loss.

**TABLE 5—Anodes Inspected in Ground Bed No. 1**

| Anode Number and Composition | Size in Inches | Backfill | Accumulated Ampere Hours |
|---|---|---|---|
| 8 (Graphite) | 4x80 | Natural soil and gypsum | 22,212 |
| 9 (Carbon) | 4x80 | Natural soil | 18,082 |
| 10 (Graphite) | 4x80 | Natural soil | 17,461 |
| 11 (Steel) | 4x80 | Natural soil | 12,702 |

**TABLE 6—Status of Table 5 Anodes at Time of Removal**

| Anode Number and Composition | Backfill | Description of Anode |
|---|---|---|
| 8 (Graphite) | Natural soil and gypsum | Length when removed—78 inches. Lower end well rounded. Anode was soft on surface with approximately ¼ inch depth of softness at center and from ¾ inch to 1 inch depth of softness at lower end. |
| 9 (Carbon) | Natural soil | Length when removed—76.5 inches. Appearance same as described for Anode No. 8. Gas bubbled from lower end when anode was removed from ground. |
| 10 (Graphite) | Natural soil | Length when removed—71.5 inches. This anode was 72 inches long when installed, having been broken in transit. Appearance same as described for Anode No. 8 |
| 11 (Steel) | Natural soil | Length when removed—66 inches. Original weight—83 pounds—final weight—60 pounds. Anode was covered with black scale over which was a coating of yellow oxide. The pH of soil was 2 (unusual) in the vicinity of anode. |

### 3.4 *Summary of Previous Inspections—Ground Bed No. 1*

Similar anodes from this ground bed were removed at the end of one, two and three years service. Results of the first inspection are contained in the First Interim Report while the second and third are contained in committee reports.

The first inspection was made after 341 days (see Table 7 for data). The second inspection was made after 712 days and the third inspection after 1104 days.

## 4.0 Fourth Annual Inspection of Anodes at Ground Bed No. 2[4]

### 4.1 *Installation and Removal Data*

The sixteen anodes in Ground Bed No. 2 (located on Crawford Drive in Jackson, Miss.) were installed on February 3-5, 1947. The rectifier was placed in operation February 6, 1947. Anodes 1, 2, 3 and 4 were removed after 360 days in operation; Anodes 5, 6, 7 and 8 were removed after 731 days in operation; Anodes 13, 14, 15 and 16 were removed after 1,123 days in operation and were replaced with new 2-inch x 80-inch graphite anodes. On March 26, 1951, after 1,508 days in operation, anodes 9, 10, 11 and 12 were removed and replaced with 2-inch x 80-inch graphite anodes.

### 4.2 *Inspection Data—March 26, 1951—Fourth and Final Inspection*

The anode types listed in Table 8 were inspected. Information obtained at time of removal for these anodes is given in Table 9.

### 4.3 *Discussion of Inspection Data*

Performance of Anode No. 11 was not as expected. Inasmuch as previous examinations of anodes of this type in this same ground bed (see Section 4.4) revealed essentially no attack, it is believed faulty installation was responsible for the damage experienced. At the time of original installation, the soil at the ground bed site was water-saturated and could easily have caved in at the bottom of anode holes, thus preventing proper packing of carbonaceous

[4] Summary performance curves and data may be found in Table 2 and Figure 2.

**TABLE 7—Ground Bed No. 1 Summary of Data From First Three Inspections**

| Anode Number and Composition (All Anodes 4x80 Inches) | Inspection Number and Time | Backfill and Time | Description of Anode |
|---|---|---|---|
| 1 (Carbon) | First (341 days) | Natural soil for 3120 ampere hours | Entire anode was roughened but particularly 6 inches on lead end. Edges on lower end were rounded but there was no appreciable taper to anode. The factory mark was badly attacked. There were small pits and depressions at random over surface. The pH was 3. |
| 2 (Graphite) | First (341 days) | Natural soil for 2385 ampere hours | Corrosion occurred at the lead end and just below the impregnation line on the lead end. The factory mark was rounded off and edges at the bottom were well rounded. There was no taper. A few depressions appeared in isolated spots and there were a few small pits. Edges of scars made during installation were rounded off. The pH was 2. |
| 3 (Steel pipe) | First (341 days) | Natural soil for 4095 ampere hours | Corrosion occurred over the entire length but particularly at the lower end which had corroded to a sharp edge. Installed weight was 83 pounds and weight when removed was 73½ pounds; weight loss was 9½ pounds and theoretical loss was 9.35 pounds. Actual loss was approximately 101.5 percent of the theoretical loss. The pH was 7. |
| 4 (Graphite) | First (341 days) | Gypsum and soil for 3485 ampere hours | The six inches at the lead end were roughened. There were numerous small pits and some depressions. Edges at the lower end were somewhat rounded; the factory mark was attacked as were the edges of scars. Over-all attack was less than on No. 1. The pH was 1. |
| 13 (Carbon) | Second (712 days) | Natural soil for 9430 ampere hours | This was the wettest location. Gas bubbled from lower end when anode was first removed. Lower end was rounded and roughened markedly; surface was soft to knife-point penetration of ¾ inch. For 4 feet above lower end, anode was fairly solid; knife-point penetration test was about ⅛ inches maximum. Upper 2.5 feet of anode had softer surface and mottled grayish color characteristic of attack; knife-point penetration ranged from ⅛ inch to ¼ inch depth with some greater penetration at small localized areas. Attack on this anode was greater than on anodes 14 or 16. The pH varied from 2 at lower end to 3 at upper end. |
| 14 (Graphite) | Second (712 days) | Natural soil for 5720 ampere hours | Attack was not as severe as on any of the other anodes and material was soft to depth of 1/16 inch on lower tip which was rounded off. Anode was softened along sides and had a dull color but there were no bad depressions. Side softness varied from ⅛ inch in depth near top to about ¼ inch near bottom. Shallow attack was noted along some scrapes or grooves that possibly were made during installation. The pH ranged from 2 at bottom tip to 4 at the top of anode. |
| 15 (Steel) | Second (712 days) | Natural soil for 10,100 ampere hours | Considerable red oxide appeared near the upper end, but the lower half was covered with black oxide. Upon washing, it was found that practically the entire anode was bright with no hard scale. Attack was concentrated at the lower end and there was a reduction in length. Heavy attack occurred all along sides with a resulting wall thinning but there was no actual penetration of the pipe wall. Original length was 80 inches and final length was 77 inches; original weight was 83 pounds and final weight was 57½ pounds. Weight loss was 25½ pounds while theoretical weight loss for 10,100 ampere hours was 23.1 pounds. Actual loss was approximately 110 percent of theoretical loss. The pH values immediately after removal were neutral on the lower half and neutral to slightly acid on the upper half. |
| 16 (Graphite) | Second (712 days) | Natural soil and gypsum for 10,540 ampere hours | Before removing anode, it was found that the soil-gypsum mixture had settled from the top of the anode leaving an air void of 12 inches to 18 inches, then about 12 inches of water, then backfill. The lower tip was heavily attacked and was rounded and very soft to a 7/8 inch depth. Sides had brown color characteristic of attack and were soft all along the length with depth of softness varying from ⅛ inch at top to ½ inch near lower end. There was one major pit in the impregnated section on one side of the anode near the top. The pit started about 1½ inch from the upper end and was 2¾ inches in diameter and ⅞ inches deep. The pH was between 1 and 2 at lower tip and all along sides. |
| 5 (Carbon) | Third (1104 days) | Natural soil for 17,547 ampere hours | The lower end was rounded with no appreciable reduction in length but was soft to depth of ¾ inch. Attack was general with no pitting of consequence. Attack appeared heaviest at ends. No deterioration of cable was noted. The pH was 2 over entire length immediately after anode's removal. |
| 6 (Graphite) | Third (1104 days) | Natural soil for 12,792 ampere hours | Lower end was rounded and had a ½ inch taper that was soft to a depth of ½ inch. The entire surface was soft to a depth of ⅛ inch with heavier attack in patches; the upper end was more firm than the lower end. There was no pitting of consequence. The pH was 2 over entire length immediately after anode's removal. |
| 7 (Steel) | Third (1104 days) | Natural soil for 14,678 ampere hours | Attack occurred largely on the lower half of anode, resulting in a sharp edge at lower end. Original length was 80 inches; final length was 74 inches. Original weight was 85 pounds and final weight was 57.5 pounds. Actual weight loss was 27.5 pounds while the theoretical loss proportioned to power consumption was 33.5 pounds. Actual loss was approximately 82 percent of the theoretical loss. |
| 12 (Graphite) | Third (1104 days) | Natural soil and gypsum for 11,413 ampere hours | The lower end was rounded and soft to a depth of ¾ inch; heavy attack was noted below the paraffin impregnation on the upper end. No pitting was observed but material was soft to a depth of ⅛ inch over the entire surface. (Broken lead to rectifier caused this anode to be inoperative for 9 months preceding inspection date.) The pH was 1 over entire length immediately after anode's removal. |

**TABLE 8—Anodes Inspected in Ground Bed No. 2**

| Anode Number and Composition | Size in Inches | Backfill | Accumulated Ampere Hours |
|---|---|---|---|
| 9 (Graphite) | 2x80 | Coke breeze | 35,668 |
| 10 (Graphite) | 2x80 | Graphite | 29,262 |
| 11 (Graphite) | 2x80 | Graphite and lime | 20,951 |
| 12 (Steel pipe) | 2x80 | Coke breeze | 15,529 |

backfill around anodes. That this probably occurred in the case of Anode No. 11 is further substantiated by the relatively low power output (a development indicative of high resistance as would be the case if part of the anode were not surrounded with carbonaceous backfill).

Anodes No. 9 and No. 10 showed remarkably little damage after four years of service with power discharge comparable to the graphite anodes in natural soil (in Ground Beds No. 1 and No. 3) which suffered advanced damage in the same period of time.

Anode No. 12 illustrates that while steel in coke

breeze does not deteriorate as rapidly as steel in natural soil, its life may be much shorter than that of graphite in carbonaceous backfill. In this case the steel anode in coke breeze was nearly at the end of its useful life (approximately 72.7 percent consumed), whereas Anodes 9 and 10 had only started to deteriorate and had a probable additional life of indeterminate length. Actually there is a good possibility that the lower end of Anode 12 became separated from the upper portion through localized corrosion and was left in the anode hole so that the actual weight of metal consumed would be less than the 56.5 percent of the theoretical rate as indicated above.

### 4.4 *Summary of Previous Inspections Ground Bed No. 2*

Reports on inspection of similar anodes removed from this ground bed at the end of one, two and three years of operation are contained in the First Interim Report and in Committee reports. Inspection data from these sources are summarized in Table 10.

## 5.0 Fourth Annual Inspection of Anodes at Ground Bed No. 3[5]

### 5.1 *Installation and Removal Data*

The sixteen anodes in Ground Bed No. 3 (located on Central Street between Harvey and Edison Street in Greenville, Miss.) were installed on March 3 and 4, 1947 and the rectifier was placed in operation on March 5, 1947. Anodes 1, 2, 3 and 4 were removed after 335 days in operation; Anodes 5, 6, 7 and 8 were removed after 707 days in operation; Anodes 13, 14, 15 and 16 were removed after 1,099 days in operation and were replaced with 2-inch x 80-inch graphite anodes. On March 28, 1951, after 1,483 days in operation, Anodes 9, 10, 11 and 12 were removed and replaced with 2-inch x 80-inch graphite anodes.

### 5.2 *Inspection Data—March 28, 1951—Fourth and Final Inspection*

The anode types listed in Table 11 were inspected.

[5] Seven summary performance curves and data may be found in Table 3 and Figure 3.

**TABLE 9—Status of Table 8 Anodes at Time of Removal**

| Anode Number and Composition | Backfill | Description of Anode |
|---|---|---|
| 9 (Graphite) | Coke breeze | The anode was solid over its entire length; face of lower end was soft to a depth of 1/16 inch. There were shovel marks on upper portion. The pH varied from 1 to 2. |
| 10 (Graphite) | Graphite | Anode was solid over its entire length except for lower 1½ inch which was soft to a depth of ¼ inch; lower edge was slightly rounded. There were shovel marks on upper portion. The pH varied from 1 to 2. |
| 11 (Graphite) | Graphite and lime | The lower 24 inches of anode was soft; lower end was soft to depth of ½ inch and lower 6 inches showed taper (current apparently discharged at lower end entirely). Anode was loose in hole—broke after removal. The pH varied from 1 to 2. |
| 12 (Steel) | Coke breeze | Original weight was 27.5 pounds and final weight was 7.5 pounds. Actual loss was 20 pounds whereas the theoretical loss proportioned to 15,529 ampere hours power consumption was 35.4 pounds. Actual loss was approximately 56.5 percent of theoretical loss. The pH was 7. |

**TABLE 10—Ground Bed No. 2 Summary of Data From First Three Inspections**

| Anode Number and Composition | Inspection Number and Time | Backfill and Time | Description of Anodes (All Anodes are 2x80 Inches) |
|---|---|---|---|
| 1 (Graphite) | First (365 days) | Coke breeze for 4,620 ampere hours. | Some small pits and depressions were detected. The pH ranged from 1 to 2. |
| 2 (Graphite) | First (365 days) | Graphite for 2,740 ampere hours. | A few small scattered pits* were observed on lower half of anode. Corrosion was less than that on Anode No. 1. The pH ranged from 1 to 2. |
| 3 (Graphite) | First (365 days) | Graphite and lime for 3,180 ampere hours. | Only three very small pits could be found but there was a white deposit over some parts of the anode. The pH was 11. |
| 4 (Steel) | First (365 days) | Coke breeze for 3,450 ampere hours. | General corrosion occurred but was concentrated at lower end. Weight when removed was 19½ pounds indicating a weight loss of 6 pounds. Weight loss proportional to power consumption was 7.87 pounds; actual loss was approximately 76.2 percent of the theoretical loss. The pH was 7. |
| 5 (Graphite) | Second (731 days) | Coke breeze for 12,800 ampere hours. | Anode was in excellent condition although a few pinholes occurred along sides. Very slight, if any, softening occurred at lower tip. Upper end was not attacked. The pH was 2 at bottom tip and 2½ to 3 all along sides to top. |
| 6 (Graphite) | Second (731 days) | Graphite for 7,880 ampere hours. | Anode was hard and firm except that the lower tip had softened. Softening occurred 1/16 inch deep at tip with corners rounded slightly and soft up to ¼ inch deep. Upper end was not softened. There were no pits or depressions but there were a few shallow pin holes. The pH was 2 at bottom tip and 2 to 3 all along sides to top. |
| 7 (Graphite) | Second (731 days) | Graphite and lime for 9,070 ampere hours. | Little attack was noted except for a few scattered pinholes along sides. Some white stains appeared along the sides but there was no softening. There was no appreciable softening at lower end. The pH was 2 on lower tip and 2½ to 3 on lower two feet of rod. Neutral point was about 2 feet from lower end. Above the neutral point, pH of about 9 was observed. |
| 8 (Steel) | Second (731 days) | Coke breeze for 8,020 ampere hours. | Original weight was 24¼ pounds; final weight was 16 pounds. Actual weight loss was 8¼ pounds and theoretical loss proportional to power consumption was 18.3 pounds. Actual weight loss was approximately 45 percent of the theoretical loss. Attack was concentrated at the lower end where bottom 15½ inches corroded away leaving a knife edge. Heavy scale formation appeared on the balance. The anode was ringed approximately 3 inches from upper end; the bottom of the groove was paper-thin at one point. Severe corrosion occurred along the butt weld in pipe with a groove covering entire length of anode. The groove occurred all the way through the pipe at points near the lower end. The pH was 7. |
| 13 (Graphite) | Third (1123 days) | Coke breeze for 18,509 ampere hours | Anode was solid over its entire surface with no visible evidence of attack. The pH was 3 at top, 2 at center, and 1 at bottom. |
| 14 (Graphite) | Third (1123 days) | Graphite for 16,978 ampere hours. | Entire anode was solid and there was no visible sign of attack. The pH was 7 at top, slightly acid at center and 2 at bottom. |
| 15 (Graphite) | Third (1123 days) | Graphite and lime for 20,348 ampere hours. | Anode was solid over entire surface. There was no visible evidence of attack. The pH was 9 at top, 8 at center, and 7 at bottom with odor of chlorine. |
| 16 (Steel) | Third (1123 days) | Coke breeze for 20,139 ampere hours. | Length when removed was 62.5 inches. Original weight was 24.5 pounds; final weight was 11.0 pounds. Actual weight loss was 13.5 pounds. Theoretical weight loss proportional to power consumption was 45.9 pounds and actual weight loss was approximately 29.5 percent of the theoretical loss. There was a large hole near the lead end. A heavy scale appeared on the anode and coke breeze was found adhering to top portion. |

*** Note:**—Small pits referred to in graphite anodes were 1/16 inch to 1/8 inch in diameter and were later found to exist on new anodes indicating that those reported above were not caused by corrosion.

**TABLE 11—Anodes Inspected in Ground Bed No. 3**

| Anode and Composition | Size in Inches | Backfill | Accumulated Ampere Hours |
|---|---|---|---|
| 9 (Graphite) | 4x80 | Natural soil | 20,049 |
| 10 (Steel) | 2x80 | Coke breeze | 26,905 |
| 11 (Graphite) | 2x80 | Coke breeze and lime | 31,355 |
| 12 (Graphite) | 2x80 | Graphite | 30,276 |

**TABLE 12—Status of Table 11 Anodes at Time of Removal**

| Anode Number and Composition | Anode Number and Type | Description of Anode |
|---|---|---|
| 9 (Graphite) | Natural soil | Anode showed attack with lower end rounded and soft to ½ inch depth; there was no appreciable loss in length. Attack was not as severe as on anodes in Ground Bed No. 1 The pH varied from 1 to 2. |
| 10 (Steel) | Coke breeze | Original weight was 24.5 pounds and final weight was 20 pounds. Actual weight loss was 4.5 pounds and the theoretical weight loss proportional to power consumption was 61.5 pounds. Actual loss was approximately 7.3 percent of theoretical loss. The pH was 7. |
| 11 (Graphite) | Coke breeze and lime | Anode was firm and showed no evidence of attack. The pH varied from 1 to 2 on anode; on lime mix backfill, pH of 7-8 was found in spots. |
| 12 (Graphite) | Graphite | Anode was firm and showed no evidence of attack. The pH varied from 1 to 2. |

**TABLE 13—Ground Bed No. 3 Summary of Data From First Three Inspections**

| Anode Number, Composition and Size (Inches) | Inspection Number and Time | Backfill and Time | Description of Anode |
|---|---|---|---|
| 1 (Graphite, 4x80) | First (335 days) | Natural soil for 2,742 ampere hours | Anode was roughened at lead end particularly just below impregnation line as was Anode No. 2 in Bed No. 1. Small individual pits and roughened areas occurred throughout length. The lower end was rounded at the edges and was tapered approximately 1/8 inch on one side. The factory mark was badly attacked. Over-all attack was less than that on similar Anode No. 1 in Bed No. 1. The pH ranged from 1 to 2. |
| 2 (Steel, 2x80) | First (335 days) | Coke breeze for 3,659 ampere hours | General corrosion was concentrated on the lower end. Anode weight when installed was 25½ pounds; weight when removed was 22½ pounds. Actual weight loss was 3 pounds whereas throretical weight loss proportional to power consumption was 8.35 pounds. Actual loss was approximately 36 percent of the theoretical loss. The pH was 7. |
| 3 (Graphite, 2x80) | First (335 days) | Coke breeze and lime for 3,835 ampere hours | A few small pinholes and depressions were noted. There was some whit coloration in spots but this was no nearly so pronounced as on Anode No. 3, Bed No. 2. The pH was 11. |
| 4 (Graphite, 2x80) | First (335 days) | Graphite for 4,565 ampere hours | Very slight attack occurred and a slight rounding of edges at ends was observed. The pH was 7. |
| 5 (Graphite, 4x80) | Second (707 days) | Natural soil for 6,240 ampere hours | Heavy attack occurred just below impregnation with softening to ½ inch depth. The impregnated area was soft to 1/16 inch depth. Along the sides of the anode softening occurred to depth of no more than 1/16 inch except at a few localized areas of attack (up to 1 inch in diameter) where softening was up to ½ inch deep in center although no material was gone. At the bottom end, the corners were rounded off and soft to ½ inch depth but the center of the bottom end had softened to only about 1/16 inch depth. The color was very dull with some brownish areas. The pH ranged from 2 at bottom to 3 at top. |
| 6 (Steel, 2x80) | Second (707 days) | Coke breeze for 9,100 ampere hours | Considerable areas of the anode were covered with thick crust up to ¾ inch and 1 inch thick. Coloring in this crust near the anode surface indicated that iron oxides may have permeated the coke breeze backfill adjacent to the anode and had a cementing effect to build up the crust. Attack on the anode appeared to be general all along its length with many deep pits and holes. The lower end corroded to a knife edge. Upper end was attacked at edges where the anode was not covered by the insulation which was used to cover the lead connection. Loss in length was ½ inch. Weight when installed was 25.0 pounds and weight when removed was 21.0 pounds. Actual weight loss was 4.0 pounds. Theoretical weight loss proportional to power consumption was 20.8 pounds; actual loss was approximately 19 percent of theoretical loss. The pH was 7. |
| 7 (Graphite, 2x80) | Second (707 days) | Coke breeze and lime for 11,010 ampere hours | Along the sides of anode, the majority of the points tested were acid, but some points were slightly alkaline. The anode was in excellent condition except for the extreme lower end where softening to about 1/16 inch depth was noted. There was no appreciable rounding of the lower end. The pH was 2 and 8 side by side on lower end of anode. |
| 8 (Graphite, 2x80) | Second (707 days) | Graphite for 11,110 ampere hours | Condition of anode was excellent with no softening except for a slight amount at the edges of the lower end where some attack was noted (not as severe as attack on Anode No. 7). The anode was difficult to remove but it was free of crust formation. The pH was 7. |
| 13 (Graphite, 4x80) | Third (1099 days) | Natural soil for 13,353 ampere hours | Both ends of the anode showed soft areas, particularly just below impregnation at upper end. The anode was soft to a depth of ½ inch at bottom. About 10 percent of the anode surface remained firm and hard. The pH varied from 1 to 2. |
| 14 (Steel, 2x80) | Third (1099 days) | Coke breeze for 19,097 ampere hours | When removed the anode had a shell of coke particles 2 inches to 6 inches thick; this shell had a pH of 5. Bright spots of steel indicated current being discharged from localized areas. Corrosion occurred along the pipe seam. Installed weight was 25.5 pounds; final weight 18.5 pounds. Actual weight loss was 7 pounds and theoretical weight loss proportional to power consumption was 43.6 pounds. Actual loss was approximately 16 percent of theoretical loss. The pH was 7. |
| 15 (Graphite, 2x80) | Third (1099 days) | Coke breeze and lime for 25,759 ampere hours | Anode was firm and hard over its entire surface. The pH was 2 over entire length. |
| 16 (Graphite, 2x80) | Third (1099 days) | Graphite for 23,657 ampere hours | Anode was firm and hard over its entire surface. The pH was 7 at top, 5 at center, and 4 at bottom. |

Information obtained at time of removal is given in Table 12.

### 5.3 *Discussion of Inspection Data*

The 1951 inspection follows the same pattern observed in preceding tests (see Section 5.4) in that the 4-inch x 80-inch graphite anode in natural soil absorbed the least amount of useful power output with the 2-inch x 80-inch steel anode in coke breeze absorbing the next least amount of useful power output. The two graphite anodes were approximately

equal in performance with respect to showing the greatest useful output with inconsequential corrosive attack.

The graphite anode in natural soil and steel anode in coke breeze performed more favorably than similar anodes in Ground Beds No. 1 and 2, respectively, indicating that soil environment may be a particular factor in determining performance of these types of anodes.

Note that the steel anode in coke breeze was only 18.4 percent consumed while a similar anode, No. 12, in Ground Bed No. 2 was 72.7 percent consumed even though it transmitted only 57.7 percent as much useful power. Likewise, the graphite anode in natural soil was less heavily attacked than a similar anode, No. 10, in Ground Bed No. 1 which transmitted only 87 percent as much useful power.

Graphite anodes in carbonaceous backfill were not attacked at all whereas some attack was noted on similar anodes in Ground Bed No. 2 (see Section 4.0).

5.4 *Summary of Previous Inspections, Ground Bed No. 3*

Reports on inspection of similar anodes removed from this ground bed at the end of one, two and three years of operation are contained in the First Interim Report and in Committee reports. Inspection data from these sources is summarized in Table 13.

## 6.0 Fourth Annual Inspection of Anodes at Ground Bed No. 4[6]

6.1 *Installation and Removal Data*

The twelve anodes in Ground Bed No. 4 (located on McHenry Street near Raymond Road in Jackson, Miss.) were installed on February 7 and 8, 1947 and the rectifier was placed in operation on February 10th. Anodes 1, 2 and 3 were removed after 357 days operation; Anodes, 4, 5 and 6 were removed after 730 days operation; Anodes 7, 8 and 10 were removed after 1,124 days operation and replaced with 2-inch x 80-inch graphite anodes. On March 26, 1951, after 1,504 days operation, Anode No. 9 was removed and replaced with a 2-inch x 80-inch graphite anode. Anodes No. 11 and 12 were not removed because a concrete drive had been built over part of the ground bed.

6.2 *Inspection Data—March 26, 1951—Fourth and Final Inspection*

The anode types listed in Table 14 were inspected. Information obtained at time of removal showed that Anode No. 9 was in excellent condition with no evidence of attack. The pH was 2.

6.3 *Discussion of Inspection Data*

Anode No. 9 was one of the set of four 4-inch x 20-inch anodes installed in holes of the same depth as those required for the 2-inch x 80-inch anodes in the remainder of the bed. The bottom 5½ feet of the 8-inch anode hole was packed with coke breeze before the short anode was placed in position and the backfilling completed with coke breeze. The coke breeze column below the short anode was depended upon to provide an anode to earth resistance for the short anodes comparable to that of the adjacent long anodes. This installation system worked reasonably well. Useful power output was comparable to that of the long anode installations and in case of Anode No. 9, power output was greater than that of either the 2-inch x 80-inch carbon or 2-inch x 80-inch graphite anodes installed in the same set.

The average current output of Anode 9 for the 1504 day test period was 0.805 amp. This is equivalent to a current density of 0.419 ampere per square foot (1.92 square feet surface area on 4-inch x 20-inch anode). Attack on the short anode was not visible and had not been apparent in preceding inspections (see Section 6.4) even though current densities were higher than on the 2-inch x 80-inch anodes installed in the same bed. The 2-inch x 80-inch anodes have 85 percent more surface area than 4-inch x 20-inch anodes.

6.4 *Summary of Previous Inspections, Ground Bed No. 4*

Reports on inspection of anodes removed from Bed No. 4 at the end of one, two and three years of operation are contained in the First Interim Report and in Committee reports. Inspection data from these sources is summarized in Table 15.

## 7.0 Graphical Comparison of Anode Performance

For each of the four ground beds, curve sheets have been prepared to illustrate the relative performance of the various anode types in that bed as well as to demonstrate changes in the total ground bed resistance and total current from anodes under test. This information is too lengthy to be published here but the entire report including all graphs and tables will be published separately. It will be available as Publication 56-1 from NACE, 1061 M & M Building, Houston 2, Texas.

## 8.0 Installation Recommendations

The following recommendations are based on the findings of the four-year test program reported on in this paper together with the results obtained from other test ground beds installed in the committee test program. Constructive comments made by committee members and other interested observers have also been used in formulating these recommendations.

8.1 *Anode Type*

Of the types tested during the program reported here (steel in soil or carbonaceous backfill, carbon in

**TABLE 14—Anodes in Ground Bed No. 4**

| Anode Number and Composition* | Size in Inches | Backfill | Accumulated Ampere Hours |
|---|---|---|---|
| 9 (Graphite) | 4x20 | Coke breeze | 29,030 |
| 11 (Graphite) | 2x80 | Coke breeze | 26,868 |
| 12 (Carbon) | 2x80 | Coke breeze | 28,561 |

* Anodes 11 and 12 were not inspected.

[6] Summary performance curves and data may be found in Table 4 and Figure 4.

soil or carbonaceous backfill, and graphite in soil or carbonaceous backfill), graphite anodes in a carbonaceous backfill appeared to give the best results based on consideration of all available data. Based on the anode types tested, it appears that graphite anodes in coke breeze backfill or a backfill comprised of a mixture of coke breeze and lime are the best practical anodes (considering both performance and cost of materials) which can be expected to give consistently good results in soil in properly designed installations.

In using graphite anodes with carbonaceous backfill, it is recommended that current densities at the anode surface be limited to one ampere per square foot of surface.

**TABLE 15—Ground Bed No. 4 Summary of Data From First Three Inspections**

| Anode Number Composition and Size (Inches) | Inspection Number and Time | Backfill and Time | Description of Anode |
|---|---|---|---|
| 1 (Graphite, 2x80) | First (357 days) | Coke breeze for 7,381 ampere hours. | Some small pits* and depressions occurred. Edges at ends were rounded very slightly. Corrosion appeared to be less extensive than on Anode No. 1 of Bed No. 2. The pH was 2. |
| 2 (Graphite, 4x20) | First (357 days) | Coke breeze column for 6,139 ampere hours. | Numerous small pits occurred over anode surface. Ends were not attacked or rounded. The pH varied from 6—7. |
| 3 (Carbon, 2x80) | First (357 days) | Coke breeze for 6,163 ampere hours. | Anode had an over-all rough appearance but only a few small pits could be found. Edges at end did not appear to be rounded. The pH was 2. |
| 4 (Graphite, 2x80) | Second (730 days) | Coke breeze for 16,600 ampere hours. | Anode was hard and firm. The largest pit was $\frac{1}{4}$ inch in diameter and approximately the same depth. A few pinhole pits were noted along sides. Neither end was attacked. The pH was 3 at lower tip and 3 to 4 along sides. (4 at top). |
| 5 (Graphite, 4x20) | Second (730 days) | Coke breeze for 12,090 ampere hours. | Anode was in excellent condition. The surface was hard and firm but roughened in small areas. One shallow groove was noted with softened material possibly $\frac{1}{4}$ inch deep. The lower end was still perfectly square and hack saw marks were visible where it was cut to length at time of installation. A few pinholes were scattered at random over the surface and were about $\frac{1}{4}$ inch deep. Some areas about $\frac{3}{8}$ inch x 2 inches were tending to groove but no soft material occurred other than at the one mentioned above. The pH was 3 on lower end and on sides. |
| 6 (Carbon, 2x45) | Second (730 days) | Coke breeze for 13,930 ampere hours. | This anode was broken when it was installed, hence short length as removed. It was fairly uniformly roughened all along one side (possibly installed in this condition). There were no definable pits, depressions, or grooves and no softened areas. The broken lower end did not appear to be attacked or softened. The pH was 3 at lower tip. Along the sides pH varied from 3 at bottom to 6 at top. |
| 7 (Graphite, 2x80) | Third (1,124 days) | Coke breeze for 26,105 ampere hours. | Anode was firm and hard over its entire surface. The pH varied from 2-3 at bottom, 4 at the center and 7 in the top quarter of the anode. |
| 8 (Graphite, 4x20) | Third (1,124 days) | Coke breeze column for 22,067 ampere hours. | Anode was firm and hard over entire surface. The pH was 6 at lower end and the balance neutral. |
| 10 (Carbon, 2x80) | Third (1,124 days) | Coke breeze for 19,666 ampere hours | Anode was firm and hard over its entire surface. The pH was 1 at bottom, 2 at center, 4 between center and top, and 7 at top. |

***Note:** Pinholes and small pits mentioned in the first and second inspection reports were found to be the same as often exist in new anodes. Such pits as were observed probably were not due to corrosive action on the anodes.

### 8.2 *Ground Bed Sites*

The best anode performance will be obtained if certain precautions are observed in selecting ground bed sites.

Anodes should be so placed that their entire length is in permanently moist soil. If this is not done and if only the lower portion of a vertically installed anode is in moist soil, the current discharge will tend to be concentrated at the lower end of the anode. If this results in current densities substantially greater than one ampere per square foot (for anodes in carbonaceous backfill) accelerated attack of the anode may result. This was found to be the case at one of the test ground beds in the committee program (although not one of the four detailed in this report). At some ground bed sites it may be necessary to auger holes to unusual depths in order that the entire anode may be placed in permanently moist soil.

One manufacturer recommends that carbon anodes be used rather than graphite if the soil at the ground bed site contains appreciable quantities of bromides or fluorides. The reason for this is that the first mentioned material will be less subject to attack. This condition was not studied in the field tests reported on here.

Where the soil at a ground bed site appears to be of such fine texture that passage of gas from the anode surface may be restricted and cause gas blocking, particular care must be provided during backfilling to permit a suitable gas escape path.

Although this was not checked in the tests reported on, one manufacturer indicated that relatively rapid anode attack could be expected in soils where there was a substantial sulfate content. Such sites should be avoided; if such sites are used, reduced anode life should be expected.

### 8.3 *Backfill*

The field tests have indicated that backfills of graphite particles, calcined coke breeze, or either material mixed with lime as an alkalizing agent have a marked beneficial effect on over-all carbon or graphite anode performance. This results in higher current output (lower anode-to-earth resistance) and less anode attack than will be obtained with anodes installed without backfill but with otherwise identical conditions. For optimum performance, it is recommended that a carbonaceous backfill always be used wherever possible.

Test results have indicated there is no great difference in current output of anodes installed with graphite particles, calcined coke breeze, or either material mixed with lime although there was some indication that the addition of lime could cause some increase in anode-to-earth resistance. This would tend to be increasingly true as the quantity of lime is increased.

Lime as an alkalizing agent was used in two of the four Mississippi test beds. Lime was used with both graphite particles and calcined coke breeze in the

ratio of one part of hydrated lime to approximately six parts of carbonaceous material by weight. During the four years of the tests reported on, the neutralizing effect of the lime reduced with time. This would be expected although postponement of development of an acid condition at the anode surface appeared to ensure maintenance of a solid attack-free anode as long as the effect of the lime was still perceptible. In view of the probable increase in total anode life and relatively small expense for lime as an alkalizing material, the use of the lime treatment appears to be a worthwhile practical procedure based on known experience to date.

Since, in these tests, there appeared to be no notable difference between the performance of graphite particles and calcined coke breeze as backfill material, the choice between the two can be made, as far as present information indicates, on the basis of delivered cost alone.

If coke breeze is used, it should be noted that uncalcined petroleum coke breeze is ordinarily of too high electrical resistivity for satisfactory use; the calcining process reduces the resistivity to a suitable value. Coal coke breeze can be of high to low resistivity depending on the degree to which volatiles have been driven off during the coking process. It is recommended that a determination be made of the electrical resistivity of any coke breeze to be used in ground bed construction and that, for adequate performance, any coke breeze having a resistivity in excess of 25 ohm-centimeters should not be used. Some coke breeze sources have resistivities of 10 ohm-centimeters or less and will result in the lowest anode-to-earth resistances—particularly if a backfill column is being used to increase the effective electrode size of an anode installation. Because of its nature, a backfill of graphite particles normally will be of satisfactorily low resistivity.

The resistivity of a coke breeze source may be checked by the "soil box" method with the coke breeze packed into the test cell (in the same manner in which it would be packed into an anode hole) and resistance measured by either a DC change-in-voltage versus change-in-current method (using DC instruments of suitable sensitivity) or by the commonly used vibrator-type AC bridge resistance measuring instruments. Since the resistivity of a coke breeze will vary with pressure, the coke breeze in the test cell should be compressed by a pressure plate applying a steady pressure of two pounds per square inch which approximates the average pressure in the usual vertical anode installation.

For good performance, a backfill material must be thoroughly compacted about the anode core. This may be accomplished by hand or power tamping as necessary although care must be taken to avoid breaking the anode or damaging the anode lead wire or connection between wire and anode. Ordinarily, a backfill with small particle size will be easier to compact than one containing large chunks. From information obtained to date, it appears that a backfill lending itself to easy installation should be graded to No. 8 mesh particle size although it is suggested that dust content be not more than 10 percent.

8.4 *Installation*

It is recommended that anodes and backfill be installed in auger holes (for vertical installations) or trenches (for horizontal installations) thus permitting a thickness of compacted backfill about the anode core approximately equal to the diameter of the anode core in use. Enough backfill material will thereby be provided for good life (it will tend to be consumed by the current discharge) and for suitably low anode-to-earth resistance when core rods of sizes presently in common useage are employed. Although thicker backfill can result in lower anode-to-earth resistance, the quantity of backfill material required increases rapidly. For example, doubling the diameter of the anode auger hole will necessitate the use of at least four times as much backfill material which can result in backfill cost greater than the anode cost.

It is recommended that backfill extend at least one foot above and below the top and bottom of a vertically installed anode as a minimum allowance for backfill settling with time and material consumption. The design engineer is free to use substantially longer backfill columns either above or below the anode proper. This is so he can take advantage of lower anode-to-earth resistances if this action will result in more economical ground bed construction at a ground bed site where soil conditions may make such a practice desirable. If such unusually long backfill columns are utilized, the current discharge from the combination still should be restricted to one ampere per square foot of the anode core rod when graphite or carbon is used.

In horizontal installations, the carbonaceous backfill used with carbon or graphite anodes should extend a minimum of one foot beyond each end of the anode. The backfill column may be made longer if advantageous for design purposes as discussed above.

It is recommended in vertical anode installations that gravel be used as backfill from the top of the carbonaceous backfill column to the surface of the ground. This procedure is recommended particularly where tight soils can be expected to be conducive to gas blocking. This will facilitate free escape of gases generated at the anode surfaces when discharging current. In critical locations from a gas blocking standpoint, it may be necessary to follow a similar procedure with horizontally installed anodes.

Although in the committee-sponsored-tests no difficulties were experienced with failure of anode lead wire connections to graphite or carbon anodes and although there was no indication, in the four-year test period, that connection difficulties would be a problem at an early date, it is recognized that difficulties have been experienced in some areas and that additional insulation has been resorted to at the anode lead wire connection. Such supplementary insulation has not been investigated on a test basis by the committee but it is recommended that if such supplementary insulation is used, it should be applied in such a manner that gas traps will not be formed. This can be particularly important at ground bed sites where the soil contains chlorides (such as in salt marshes) where chlorine may be liberated at

the anode. If wet chlorine is trapped on the anode surface at the lead wire connection, aggravated attack can be expected on carbon or graphite anodes.

In order to take full advantage of good anode life, it is recommended that the quality of all underground conductors, electrical connections, insulation, and installation technique be consistent with the quality of the basic anode installation.

Underground conductors should be insulated for underground use with the proper moisture resisting insulation and should have a jacket that will offer mechanical protection and resistance to the environment in which it will be placed. Electrical connections should be soldered or brazed by suitable methods. Another alternative is to use suitable mechanical devices if such devices and the wires they are connecting are coated with a suitable grease prior to making them up so that all voids in the connection proper will be completely filled. All underground connections should be insulated to be at least equal to the general conductor insulation. Care should be taken to avoid damage to conductor insulation during backfill (using selected backfill where necessary) so as to avoid insulation breaks that could eventually cause severance of the conductor through corrosion resulting from current discharge.

A Report of Technical Unit Commitee T-2G on Coal Tar Coatings for Underground Use★

# Tentative Recommended Specifications And Practices for Coal Tar Coatings For Underground Use


## Abstract

Recommendations are given for practices to be adopted in the underground use of coal tar coatings. Topics discussed include coating requirements, long term performance, coal tar primer, coal tar enamels, and application of coal tar coatings to pipe.


## Introduction

TWO YEARS AGO NACE was requested to prepare a "Minimum Requirements for the Protection of Buried Pipe Lines." The request was approved by the NACE Technical Practices Committee and the project was assigned to Group Committee T-2 on Pipe Line Corrosion.

Several individual unit committees under T-2 were assigned a portion of the project. This report represents the first assignment to be completed. As other unit committees complete their assignment, their report will be published in this section of *Corrosion*.

After all assignments have been completed, a task group assigned by the chairman of Group Committee T-2 will prepare the "Minimum Requirements for the Protection of Buried Pipe Lines." The reports prepared by individual T-2 unit committees will be included or referred to in the T-2 "Minimum Requirements."

## 1. Coating Requirements

Minimum requirements of a suitable pipe line coating should comprise a relatively high melting point thermoplastic bituminous coating of known permanent low water absorption, resistance to product spillage, high electrical resistivity meeting the physical properties herein below specified, plus a conventional type asbestos felt wrapper as a shield.

## 2. Long Term Performance

Enamel specifications given in this report are based upon the known proven excellent performance of such products during many years of service. The properties tabulated do not in themselves constitute a guarantee of good performance except when they refer to coal tar enamel coatings. A material of unknown composition might be made to meet the requirements tabulated, but would not necessarily be a good protective coating.

## 3. Coal Tar Primer

The primer suitable for use with the type of enamel selected may consist of coal tar pitch and solvents blended to produce a fluid product suitable for brush or mechanical application.

★T. F. P. Kelly, Mavor-Kelly Company, Houston, Texas, chairman.

## 4. Coal Tar Enamels

Table 1 lists the three types of coal tar enamels widely produced and commercially available. For convenience in selection, the three types have been subdivided.

## 5. Application of Coal Tar Coatings to Pipe

5-1. *General*

The cleaning, coating and wrapping of the pipe shall be performed by the contractor in accordance with the following recommendations to the satisfaction of the company's authorized representative. Deviations from the recommendations occasionally may be warranted under special conditions. The work required under this program includes the furnishing of all labor, equipment and service necessary for the application of the coating and wrapping materials.

All equipment, type and condition thereof, employed by the contractor for the application of the coating and wrapping materials shall be subject to the approval of the company's authorized representative.

The following recommendations are made regarding coating materials:

1. All materials applied to the company's pipe by the contractor shall be standard quality mutually acceptable to both parties.
2. Coating and wrapping material shall be handled in such a manner as to prevent damage to the materials.
3. The responsibility for storage, handling,

**TABLE 1—Physical Properties of Coal Tar Enamels**

| TEST | TYPE 1 | | TYPE 2 | TYPE 3 | |
|---|---|---|---|---|---|
| | Low Filler | High Filler | | Low Penetration | High Penetration |
| Soft. Point, Degrees F (R&B) | 180–200 | 195–205 | 190–205 | 220 Min. | 220 Min. |
| Ash (Percent) | 17–27 | 30–40 | 20–30 | 20–30 | 25–35 |
| Specific Gravity at 77 F. | 1.40–1.55 | 1.50–1.65 | 1.40–1.55 | 1.40–1.55 | 1.40–1.60 |
| Penetration at 77 F.<br>at 115 F. | 3 Max.<br>8 Max. | 2 Max.<br>3–8 | 2–7<br>10–25 | 4–10<br>12–25 | 10–20<br>15–55 |
| Maximum Sag, 5 Hours at 120<br>5 Hours at 140<br>5 Hours at 160 | 1/16″<br>....<br>.... | 1/16″<br>....<br>.... | ....<br>1/16″<br>.... | ....<br>....<br>1/16″ | ....<br>....<br>1/16″ |
| Crack Test: 5 Hours at +30 F<br>5 hours at +10 F<br>5 hours at —10 F<br>5 hours at —20 F | None*<br>....<br>....<br>.... | None<br>....<br>....<br>.... | ....<br>None<br>....<br>.... | ....<br>....<br>None<br>.... | ....<br>....<br>....<br>None |

* If softening point specified above 190 F., no crack at 45 F.
All softening point, ash, specific gravity and penetration tests to be determined in accordance with standard ASTM methods. Sag and crack tests to be run in accordance with AWWA test methods.

and use of the coating materials shall rest upon the contractor.

5-2. *Cleaning and Priming*

The following recommendations are made regarding cleaning:

1. Pipe surfaces shall be thoroughly cleaned and dried before the primer is applied, and shall be free of dirt, grease, oil, rust, scale or other foreign matter.
2. The pipe shall be cleaned by one of the following, mutually agreed upon methods: (a) grit blast, (b) sand blast, (c) mechanical cleaning.

5-3. *Priming*

The following recommendations are made regarding priming:

1. One uniform coat of primer, compatible with the type of enamel to be used, and free from floods or runs shall be applied immediately after pipe has been cleaned.
2. Primer coverage shall be such as to ensure maximum bond between the steel surface and the enamel coating.
3. Atmospheric conditions, type and coverage of primer determines the drying time. If the primer coat is found to be unsatisfactory, the pipe shall be reprimed.
4. Primer thinner shall be considered as a material to be used in emergencies only.

5-4. *Coating*

The following recommendations are made regarding coatings:

1. The primed pipe surface shall be free from moisture or any foreign matter immediately prior to the application of the hot coating.
2. All enamel coating shall be broken into lumps suitable for the heating equipment employed and shall be free of any foreign material.
3. The loaded heating kettle shall be brought to application temperatures in a manner to prevent damage to the coating material.
4. The kettles shall be equipped with mechanically operated agitators so as to supply uniform hot material to the coating and/or wrapping machines. In case of small patching kettles, coating may be stirred with metal mortar type hoes.
5. Kettles shall not be used as a continuous coating supply source by adding unmelted coating material after application temperatures have been reached. Kettles shall be completely emptied of one charge, and cleaned when necessary, before recharging.
6. Application temperature of the enamel shall comply with the manufacturer's recommendations.
7. The enamel shall be applied to the primed pipe in a continuous and uniform specified thickness by approved mechanical coating and/or wrapping machine.
8. Specified wrappers shall conform to the recommendations of NACE Committee T-2.
9. Electrical inspection of the finished coating shall conform to the recommendations of NACE Committee T-3.
10. When coating welded field joints or repairing damage areas, the coating shall meet the same specification as the original mechanically applied coating.

5-5. *Handling*

The coated pipe shall be handled in a manner which will protect the coating at all times. All handling equipment shall be approved by the company's authorized representative.

5-6. *Lowering and Backfilling*

The lowering in and backfilling shall be done in such a manner that protective coating will not be injured in any manner.

# Progress Report of Task Group T-4F-1 On Water Meter Corrosion*


## Abstract

The susceptibility of water meters to corrosion is discussed with particular attention paid to the manner in which corrosion affects the operation of the individual parts. Case studies are given with accompanying illustrations. Other topics discussed include the economic aspects of water meter corrosion, the nature of the corrosion problem and factors contributing to corrosion. Suggestions are made regarding the type of research to be conducted in future investigations.


## Introduction

A WATER METER is a liquid measuring instrument. It is expected to perform satisfactorily over an extended period of time totally immersed in potable waters.

Materials of construction used in water meters are normally of the copper base alloy group. Because of this fact certain areas of investigation automatically can be eliminated and certain generalizations made regarding corrosion resistance. In this connection it is known that:

1. Water meters are not subject to the rusting type of deterioration associated with ferrous alloys.
2. Water meter alloys can be expected to be relatively sensitive to the dissolved oxygen and carbon dioxide content of the potable waters.
3. Water meter alloys will be sensitive to oxidizing elements.
4. Dezincification will not be a problem if alloys are selected to avoid this trouble.

In analyzing the meter itself for vulnerability to corrosive attack it becomes evident that whenever tolerances and clearances are close, corrosion becomes critical. A sketch of a typical meter is shown in Figure 1.

The heart of a metering device such as the one pictured is the chamber and disc assembly (arrow No. 1 on the sketch). The accuracy of the meter depends on clearances between the disc and mating surfaces of the chamber. Tolerances are held very close to extract maximum accuracy from the meter.

The accuracy of this instrument can be adversely affected by corrosion where: (1) the materials of the chamber and/or disc are attacked so as to destroy the clearance picture originally obtained, and; (2) deposition of corrosion products occurs which may reduce clearances to zero and affect the operation of the meter.

It is obvious that the chamber and disc assembly is the most critical area from a corrosion standpoint. The second most critical assembly is probably the gear train (arrow No. 2 in sketch). This part transmits the motion of the disc in the chamber to the meter spindle.

It is found that attack on the gear train can take the following forms:

1. Degredation of gears causing tooth failure, excessive friction, etc.
2. Attack on the spindle, causing failure, excessive friction, wear, etc.
3. Deposition of corrosion products, causing the gear train to jam.

The meter spindle (arrow No. 3 in sketch), is a third point of attack. It is probably less critical than the other two, but is the last totally immersed component in the driving train from chamber to register. The spindle picks up angular motion from the gear train through a suitable coupling, passes through a stuffing box, and transmits the rotation to the register (arrow No. 4 in sketch), which integrates and records the quantity of water passing through the meter.

Because of its location at the end of the train and its relative isolation from other components, jamming of the spindle is not a problem. The main source of trouble here would be a twisting off of the spindle caused by an attack on the metal which would reduce the section necessary to transmit applied torque.

The remaining component of the meter which is constantly in contact with the water is the housing. Because of the mass of the housing castings, failure due to perforation of the housing is virtually nonexistent. The only points which could be considered critical would be the machined mating surfaces where the housing receives the chamber. Because

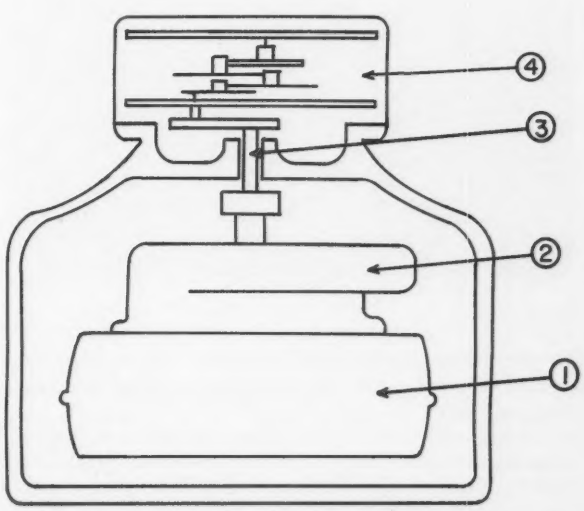


**Figure 1—A typical water meter. Arrows indicate the following components: (1) chamber and disc assembly, (2) gear train assembly, (3) meter spindle, and (4) register.**

*R. W. Henke, Badger Meter Manufacturing Co., Milwaukee, Wisconsin, chairman.

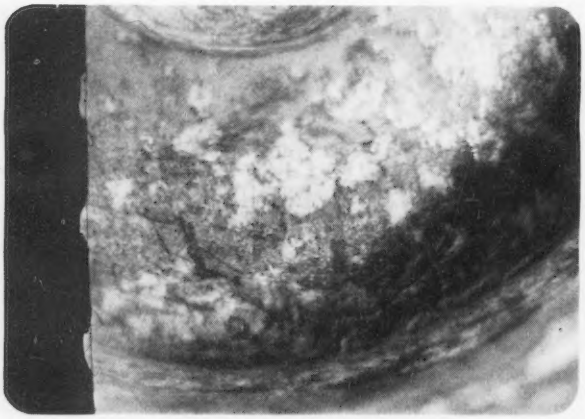

Figure 2

Figure 3

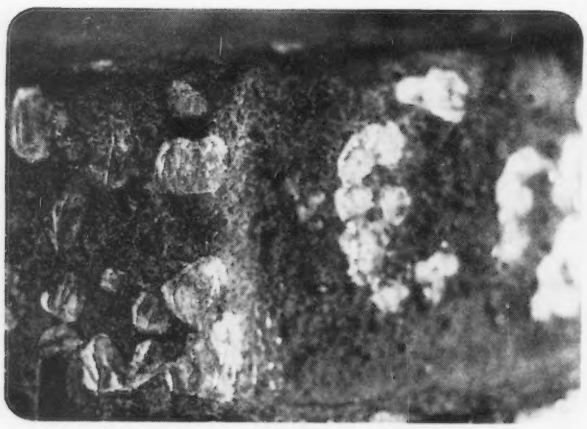

Figure 4

Figure 5

Figure 6

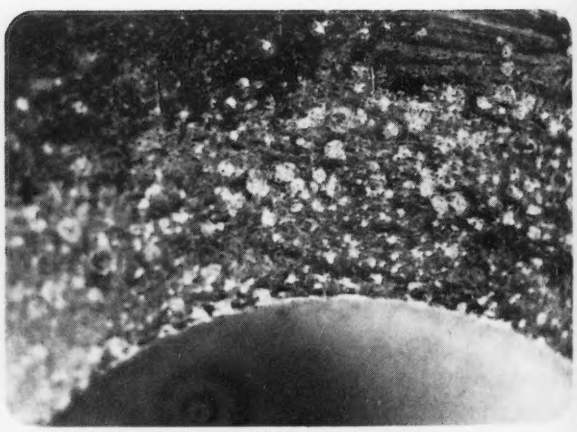

Figure 7

these surfaces serve only as retaining devices, attack would need to be extraordinarily severe to cause any concern.

Of the critical components outside the housing, the register deserves the most consideration. It contains the integrating gears and counting mechanism which converts the rotations of the meter spindle into a numerical indication of the quantity of water which has passed through the meter.

Although the corrosion associated with the water immersed components is dependent to a large extent on the chemical composition of the potable water being metered, the register is affected primarily by atmospheric corrosion. Occasionally, a register might be immersed for a short time, as in a pit installation when the pit fills with water, but the normal condition is atmospheric exposure.

The register gears and spindles, number wheels,

and dial faces are the components which should be watched most closely for corrosion. Attack of other components, such as meter housings, would be more likely to be objectionable from an appearance standpoint than from a functional one.

### Nature of the Corrosion Problem

As nearly as can be determined at this stage of the investigation, the water meter corrosion picture looks like this:

1. Acute corrosion problems seem to be localized.
2. The ratio of corrosion complaints of all types to meter production seem to be of the order of 1 to 6,000-8,000. The ratio of critical corrosion complaints to total meter production would be even lower.
3. A sizable portion of corrosion complaints are actually not a result of corrosion of the meter itself, but come about because of the deposition of corrosion product from corrosion elsewhere in the system.

### Economics of the Corrosion Problem

Unfortunately, the committee has not yet been able to obtain any quantitative data on the costs to municipalities and manufacturers of water meter corrosion.

What has been discovered, in a qualitative way, is that as with almost all *equipment applications*, a compromise exists between the ultimate desired performance of the equipment and the level of performance for which the customer is willing to pay. Water meters, like other equipment, could be built so they could last forever, but no one would want to pay for them. Therefore, the customers and manufacturers agree on a suitable meter which will give good performance over a reasonably long service life and at a cost which can be practically borne by the customer. This design is outstanding for the general application. It is in the localized areas, previously referred to, that corrosion becomes troublesome.

The problem before the industry, in general, and this committee specifically, is to determine what steps can be taken to alleviate these local corrosion problems without penalizing meter users as a whole.

### Analyses of Specific Corrosion Samples

Figure 2 shows a typical chamber bottom exhibiting pitting attack. Chemical analysis of the corrosion products indicated the presence of lead, iron, copper, aluminum, calcium and magnesium in the corrosion products. These elements probably were present in the water in the form of carbonates and hydroxides. Nitrates were absent. Carbonates, chlorides, sulfates and traces of phosphates were present.

The presence of iron and chloride radicals indicates the possibility of a combination which would yield unstable ferric chloride. This in turn could hydrolyze to give hydrochloric acid which could be a major cause of the attack.

Figure 3 shows the ball seat in the chamber of Figure 2, and Figure 4 shows the outside area of the chamber. This specimen came from the Braman, Oklahoma area.

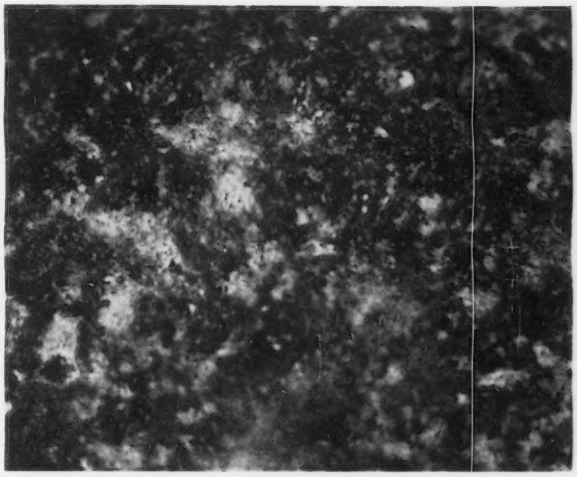

**Figure 8—Corrosion deposit consisting of copper chloride, ferrous oxide, ferric oxide and a complex of nickel carbonate and nickel hydroxide.**

Figure 5 illustrates another type of corrosion problem—the deposition of corrosion product carried by the water stream from elsewhere in the system. Obviously, copper base alloys do not exhibit this typically ferrous alloy rusting. It could have been brought in only from the system where iron equipment is utilized.

One of the implications of deposition of rust on the bronze alloy is illustrated in Figure 6. Here a concentration cell action apparently was set up beneath the rust deposits with resultant actual attack of the chamber. Figure 7 illustrates the brilliant blue-green corrosion deposit characteristic of copper carbonate and copper hydroxide. Mixed with these compounds in the deposits are copper oxide and iron oxide.

Figure 8 shows a corrosion deposit consisting of copper chloride, ferrous oxide, ferric oxide, and a complex of nickel carbonate and nickel hydroxide.

In order to better identify the corrosion products in deposits on meter parts, the laboratory of one of the participating groups set out to deliberately "grow" the different types of corrosion products by exposing water meter alloys to the pure reagent.

### Conclusions

It would appear from the preceding discussion that water meter corrosion is not an overwhelming, wide spread problem, but rather one of a localized nature. Potable waters vary widely from place to place and some locations have more active water than others due to mineral deposits in the area, pick-up from ground run-off, variations in technique and degree of water treatment, etc. For this reason it becomes necessary to temper any thinking along the lines of mitigation recommendations with the idea that the majority of water meter users should not be penalized. Perhaps the concept of adequate service life will have to be redefined to allow for several

grades or classes to correspond with the severity of corrosive environment. After all, exactly what does constitute adequate service life?

A second approach to the problem would be to set up grades of meters corresponding to the severity of the corrosive environment. These grades of meters would carry price differentials to compensate for the differential cost of their production.

Still another approach could be to set up closer controls on water treatment and grade the required treatment to match the severity of the corrosive environment.

Obviously, the scope of the work is broad.

### Future Committee Program

This first report has been written more to define the scope of the committee's activities and to stimulate interest in the work than to report any conclusive findings.

Future efforts could well parallel the following lines:

1. Quantitative data could be obtained on the incidence of failure due to corrosion.
2. Attempts could be made to classify waters by type and to correlate this with the kind and severity of water meter corrosion.
3. Attempts could be made to define and correlate other environmental influences on water meter corrosion (stray current, galvanic coupling, etc.)
4. Data could be collected and catalogued on the performance of various materials in a water meter application.
5. Recommended practices could be established for corrosion mitigation in the water meter field.

The committee feels that there is a challenge in the problems involved in water meter corrosion. It would like to extend an invitation to those who are interested to participate with the committee.

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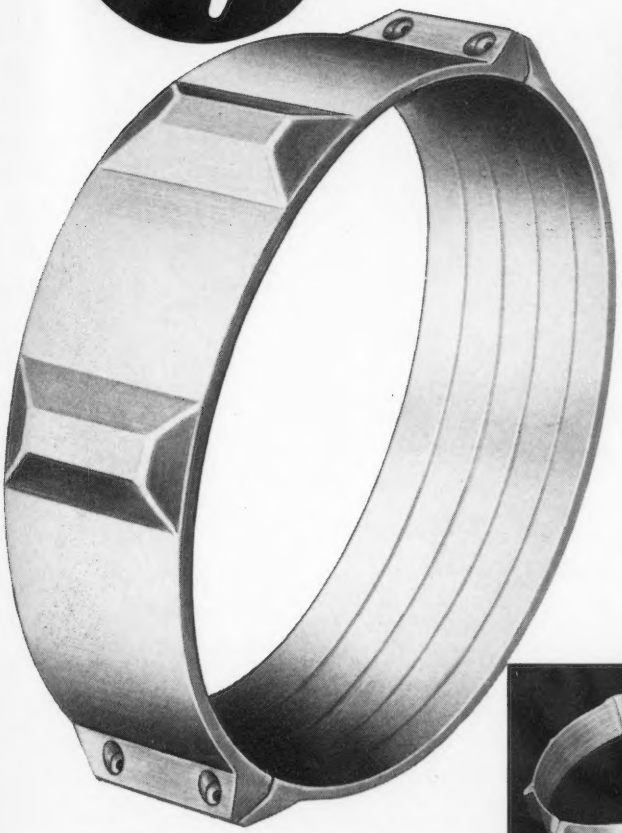

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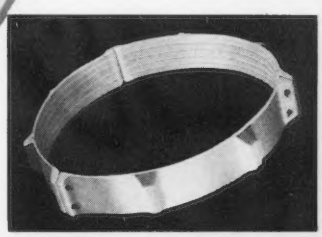

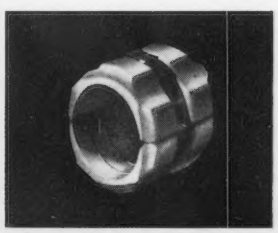

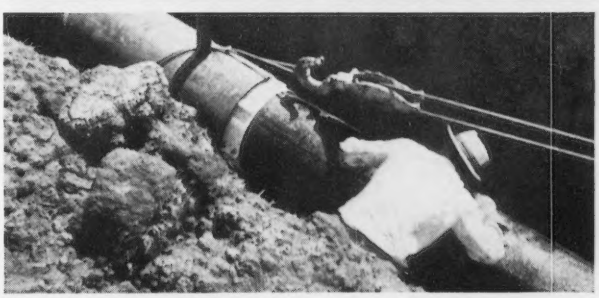

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# 62 Technical Committees to Meet at New York

**Tentative Schedule of Technical Committee Meetings**
(12th Annual Conference, New York, March 12-16)

| Day | Committees Meeting |
|---|---|
| **Monday** | |
| Morning | T-1 T-2C,F,K T-4F T-5A-5,6 T-6A |
| Afternoon | T-1 T-2B,D,G T-3B,C T-4D T-4F-1 T-5A,-1,2,4 T-5B-2 T-6R |
| **Tuesday** | |
| Morning | T-1F,H T-2A-2 T-2H T-3D,-1,G T-4B-1,2,6 T-5A-3 T-5B,D T-6B |
| Afternoon | T-2A,E,J T-3H T-4B,-3,4,5 T-4E |
| **Wednesday** | |
| Morning | T-1C T-1D-1 T-3A,E,E-1 T-4A T-6C,H |
| Afternoon | T-1G,K T-3E-2 T-3F |
| **Thursday** | |
| Morning | T-1D T-5E T-6E,G,K |
| Afternoon | T-1B,J |
| **Friday** | |
| Morning | T-5B-2 |

T-1 Corrosion in Oil & Gas Well Equipment, All Day Monday

T-1B Condensate Well Corrosion, Thursday p.m.

T-1C Sweet Oil Well Corrosion, Wednesday a.m.

T-1D Sour Oil Well Corrosion, Thursday a.m.

T-1D-1 Fundamentals of Corrosion Wednesday a.m.

T-1F Metallurgy, Tuesday a.m.

T-1G Sulfide Stress Corrosion Cracking, Wednesday p.m.

T-1H Oil String Casing Corrosion, Tuesday a.m.

T-1J Oil Field Structural Plastics, Thursday p.m.

T-1K Inhibitors for Oil & Gas Wells, Wednesday p.m.

T-2A Galvanic Anodes, Tuesday p.m.

T-2A-2 Ribbon Anodes, Tuesday a.m.

T-2B Anodes for Impressed Currents, Monday p.m.

T-2C Minimum Current Requirements, Monday a.m.

T-2D Standardization of Procedures for Measuring Pipe Coating Leakage Conductance, Monday p.m.

T-2E Internal Corrosion of Product Pipe Lines and Tanks, Tuesday p.m.

T-2F Internal Corrosion of Crude Oil Pipe Lines and Tanks, Monday a.m.

T-2G Coal Tar Coatings for Underground Use, Monday p.m.

T-2H Asphalt Type Pipe Coatings, Tuesday a.m.

T-2J Wrappers for Underground Pipe Line

T-2K Prefabricated Plastic Film for Pipe Line Coating, Monday a.m.

T-3A Corrosion Inhibitors, Wednesday, a.m.

T-3B Corrosion Products, Monday p.m.

T-3C Annual Losses Due to Corrosion, Monday p.m.

T-3D Instruments for Measuring Corrosion, Tuesday, a.m.

T-3D-1 Electrical Holiday Inspection of Coatings, Tuesday a.m.

T-3E Railroads, Wednesday a.m.

T-3E-1 Corrosion of Railroad Tank Cars, Wednesday a.m.

T-3E-2 Corrosion in Railroad Hopper Cars, Wednesday p.m.

T-3F Corrosion by High Purity Water, Wednesday p.m.

T-3G Cathodic Protection, Tuesday a.m.

T-3H Tanker Corrosion, Tuesday p.m.

T-4A Effects of Electrical Grounding on Corrosion, Wednesday a.m.

T-4B Corrosion of Cable Sheaths, Tuesday p.m.

T-4B-1 Lead and Other Metallic Sheaths, Tuesday a.m.

T-4B-2 Cathodic Protection, Tuesday a.m.

T-4B-3 Tests and Surveys, Tuesday p.m.

T-4B-4 Protection of Pipe Type Cables, Tuesday p.m.

T-4B-5 Non-Metallic Sheaths and Coatings, Tuesday p.m.

T-4B-6 Stray Current Electrolysis, Tuesday a.m.

T-4D Corrosion by Deicing Salts, Monday p.m.

T-4E Corrosion by Domestic Waters, Tuesday p.m.

T-4F Materials Selection for Corrosion Mitigation in the Utility Industry, Monday a.m.

T-4F-1 Water Meter Corrosion, Monday p.m.

T-5A Chemical Manufacturing Industry, Monday p.m.

T-5A-1 Sulfuric Acid, Monday p.m.

T-5A-3 Acetic Acid, Tuesday a.m.

T-5A-4 Chlorine, Monday p.m.

T-5A-5 Nitric Acid, Monday a.m.

T-5A-6 HF Corrosion, Monday a.m.

T-5B High Temperature Corrosion, Tuesday a.m.

T-5B-2 Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry, Monday p.m., Friday a.m.

T-5D Plastic Materials of Construction, Tuesday a.m.

T-5E Stress Corrosion Cracking of Austenitic Stainless Steel, Thursday a.m.

T-6A Organic Coatings and Linings for Resistance to Chemical Corrosion, Monday a.m.

T-6B Protective Coatings for Resistance to Atmospheric Corrosion, Tuesday a.m.

T-6E Protective Coatings in Petroleum Production, Thursday a.m.

T-6G Surface Preparation for Organic Coatings, Thursday a.m.

T-6H Glass Linings and Vitreous Enamels, Wednesday a.m.

T-6K Corrosion Resistant Construction with Masonry and Allied Materials, Thursday a.m.

T-6R Protective Coatings Research, Monday p.m.

T-6C Protective Coatings for Resistance to Marine Corrosion, Wednesday a.m.

## *Many Important Topics Listed on March 12-16 Program*

Sixty-two technical committees of the National Association of Corrosion Engineers are scheduled to hold meetings during the 1956 NACE Conference, Statler Hotel, New York City, March 12-16. Below are names of each committee with a short description of its activities and what is planned for the March meeting.

**T-1—Corrosion in Oil and Gas Well Equipment**

On Monday, March 12 there will be an all-day joint meeting of all the unit committees under Group Committee T-1. During the first part of this meeting the chairmen of the ten unit committees will present reports of activities of their respective committees. The latter part of the meeting will be devoted to a general roundtable discussion on problems and new developments concerning corrosion in oil and gas well equipment.

It is expected the final draft of the T-1 book on "Corrosion of Oil and Gas Well Equipment" will be ready for discussion at this meeting. An editorial committee appointed by the chairman of T-1 recently reported that all but one chapter of the book has been completed. The book is being written for, and at the request of the American Petroleum Institute.

**Unit Committee T-1A—Corrosion in Oil and Gas Well Equipment, Los Angeles Area**

Unit Committee T-1A will not hold a meeting during the conference. However it is expected a representative of the committee will be present at the T-1 meeting to present a progress report. A report is being prepared by T-1A on a survey of corrosion control in California oil wells. The first report by the committee on this subject was published beginning on Page 248 of the August 1954 issue of Corrosion.

**Unit Committee T-1B—Condensate Well Corrosion**

Last year Unit Committee T-1B presented a report to T-1 on current pactices used to control corrosion in condensate wells. This year it is expected the committee will discuss any new practices developed or changes in old practices for control of corrosion in condensate wells.

**Unit Committee T-1C—Sweet Oil Well Corrosion**

Unit Committee T-1C will meet on the morning of Wednesday, March 13. It is expected T-1C will hear a report from task groups on field practices and experimental aspects concerning water-independent sweet-oil well corrosion and a task group on experimental aspects concerning water-dependent sweet-oil well corrosion.

The T-1C task force assigned the study of field practices concerning water-dependent sweet-oil well corrosion completed a report and presented it to T-1 at the October meeting of the commit-

(Continued on Page 83)

## Many Topics Listed—

(Continued from Page 82)

tee. The report is tentatively scheduled for publication in the March issue of Corrosion.

**Unit Committee T-1D, Sour Oil Well Corrosion**

Unit Committee T-1D will meet on the morning of Thursday, March 14. The committee will discuss progress on its interim report on sour oil well corrosion. Questions the committee is attempting to find answers for include: Volume of well fluids to be used to flush an inhibitor into the well; determination of the value of flushing with well fluids in relation to increasing inhibitor effectiveness; and, the criterion for judging amount of inhibitor to be used in a sour oil well.

It is expected the Task Force T-1D-1 on Fundamentals of Corrosion will report progress of work to T-1D.

**Unit Committee T-1F—Metallurgy**

Unit Committee T-1F will meet on the morning of Tuesday, March 13. T-1F has spent considerable time this year in preparation for a symposium on Steel Metallurgy and Corrosion which is to be presented as part of the technical program at the conference. The meeting will probably include a discussion of the papers to be presented at the symposium. Papers now scheduled for presentation at the symposium are: The Role of Iron Carbides and Impurities in the Corrosion of Plain Carbon Steel by D. A. Shock, F. J. Radd, R. L. McGlasson and L. H. Crowder, Continental Oil Co., Ponca City, Oklahoma; Steel Surface Properties Affect Internal Corrosion Performance of Tin Plate Containers, by A. H. Willey, American Can Company Research Laboratories, Maywood, Illinois; The Influence of Temperature on Corrosion Fatigue, by I. Cornet and Sincha Golan, University of California, Berkeley; A Statistical Corrosion Fatigue Study of a Plain Carbon Steel, by F. J. Radd and R. L. McGlasson, Continental Oil Company, Ponca City, Oklahoma and A Study of Galvanic Corrosion by J. T. Waber, Los Alamos Scientific Laboratories, Los Alamos, New Mexico.

**Unit Committee T-1G—Sulfide Stress Corrosion Cracking**

Unit Committee T-1G will meet in the afternoon on Wednesday, March 14. The committee will discuss the final report on the research project being completed at Yale University on sulfide stress corrosion cracking. Any future work indicated as feasible by the results of the research program will be discussed.

A report will be made on a field test, based on minimum design prepared by a company represented on the committee.

A task group of T-1G has prepared a tentative test procedure for evaluating susceptibility of materials to sulfide corrosion cracking. Since the method departs in a significant degree from test procedures used by individual companies it was considered essential that evaluation of the procedure be made by several laboratories before the committee could approve the tentative procedure. It is expected reports will be received from laboratories and results discussed at the meeting.

(Continued on Page 84)

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## Many Topics Listed—

(Continued From Page 83)

**Unit Committee T-1H—Oil String Casing Corrosion**

Unit Committee T-1H will meet on the morning of Tuesday, March 13. T-1H will discuss the use of cathodic protection for control of oil string casing corrosion. It is expected reports will be heard from several members of the committee on their experiences with oil string casing corrosion problems. Reports will be heard from two task groups of T-1H that are active in the Western Kansas and the West Texas-New Mexico areas.

**Unit Committee T-1J—Oil Field Structural Plastics**

Unit Committee T-1J will meet on the afternoon of Thursday, March 15. In addition to general discussions on plastics used in oil production two reports will be heard on glass reinforced plastic pipe test sections installed in high pressure installations.

**Unit Committee T-1K—Inhibitors for Oil and Gas Wells**

Unit Committee T-1K will meet on the afternoon of Wednesday, March 14. T-1K continues to study tests run using the T-1K standardized test for screening inhibitors. The committee will discuss results of tests run with the objective of determining if there is a need for changing or amending the standardized procedure.

**Unit Committee T-2A—Galvanic Anodes**

Unit Committee T-2A will meet on the afternoon of Tuesday, March 13. The committee will hear a report from the task group on ribbon anodes. It is expected a member of the committee will report on backfills and on the effect of quality on anode performance. This member has reported that anodes installed with Krilium in the backfill are still giving stepped-up current outputs. Reports on other galvanic anode installations are expected to be presented and discussed at the meeting.

**Unit Committee T-2B—Anodes for Impressed Currents**

Unit Committee T-2B will meet on the afternoon of Monday, March 12. A report on comparative tests of graphite, carbon and steel anodes entitled "Final Report on Four Annual Inspections at Ground Beds Installed for Unit Committee T-2B Tests" is published in the Technical Section of the January, 1956 issue of Corrosion. In addition to discussions of this report it is expected a report will be given by the T-2B task group assigned to assemble information on the use of high silicon cast iron as an anode material. Progress on the committee project to prepare a report on ground bed design techniques will be reported.

**Unit Committee T-2C—Minimum Current Requirements**

Unit Committee T-2C will meet on the morning of Monday, March 12. The committee will hear a report on the completed committee tests conducted on 240 feet of bare pipe line buried in eastern Pennsylvania. Various measurements were made. An effort was made to use the null method for specific correlation between time and protection. The potential gradient between the pipe and the ground surface was investigated in an effort to establish a method of measuring potentials accurately on the ground surface over the pipe. Additional committee projects will be reported on. These include a study to establish current required to polarize new and graphatized cast iron and progress on the committee report on Minimum Current Requirements for Cathodic Protection of Buried Pipe Lines.

**Unit Committee T-2E—Internal Corrosion of Product Pipe Lines and Tanks**

Unit Committee T-2E will meet on the morning of Tuesday, March 13. On the basis of completed reproducibility tests Unit Committee T-2E has decided to initiate a cooperative coupon test program. The purpose of the program will be to obtain more data on the effectiveness of various inhibitors and permit collection of more information on uninhibited products pipe lines. Coupons from one heat and of one analysis will be used in the program. Each cooperating member will expose coupons in this particular line, rate his coupons, photograph them and preserve them. In addition, he will report size of line, flow per hour and inhibitor employed with dosage. Three points to be taken into consideration in the coupon tests are coupon positioning and mounting, rating of coupons and surface preparation of coupons. This test program will be discussed at the committee meeting.

**Unit Committee T-2F—Internal Corrosion of Crude Oil Pipe Lines and Tanks**

Unit Committee T-2F will meet on the morning of Monday, March 12. Reports from task groups working on design and operation of pipelines and tanks in sour crude services are expected to be given at the meeting.

**Unit Committee T-2G—Coal Tar Coatings for Underground Use**

Unit Committee T-2G will meet on the afternoon of Monday, March 12. T-2G recently completed a "Tentative Recommended Specifications and Practices for Coal Tar Coatings for Underground Use." This report is published in the Technical Committee Activities Section of the January, 1956 issue of Corrosion. It is expected the committee will discuss the report at the meeting.

**Unit Committee T-2H—Asphalt Type Pipe Coatings**

Unit Committee T-2H will meet on the morning of Tuesday, March 13. T-2H currently is working on recommended specifications and practices for asphalt type coatings for underground use. It is excepted a draft will be discussed at the meeting.

**Unit Committee T-2J—Wrappers for Underground Pipe Line Coating**

Unit Committee T-2J will meet on the afternoon of Tuesday, March 13. T-2J is working on recommended practices in the selection of wrappers for underground pipe line coating. Reports from task groups on several different types of wrappers are expected to report to the committee at the meeting.

**Unit Committee T-2K—Prefabricated Plastic Film for Pipe Line Coating**

Unit Committee T-2K will meet on the morning of Monday, March 12. Five task groups of T-2K on History and Results, Physical Characteristics, Research and Development, Application and Standards will report progress to the committee.

**Unit Committee T-3A—Corrosion Inhibitors**

Unit Committee T-3A will meet on the morning of Wednesday, March 14. Task groups of the committee assigned to study inhibitors within a limited classification group are expected to report to the committee.

**Unit Committee T-3B—Corrosion Products**

Unit Committee T-3B will meet on the afternoon of Monday, March 12. T-3B has completed a large part of its' Bibliography of Corrosion Products. Completed portions include bibliographies on the following: zirconium, tin and tin alloys, titanium, stainless steels, iron and steel, copper and copper alloys, zinc, silver, lead and aluminum. Additional bibliographies on corrosion products of magnesium, chromium and nickel are expected to be complete and ready for discussion at the meeting. The committee will discuss the bibliography and its publication.

**Unit Committee T-3C—Annual Losses Due to Corrosion**

Unit Committee T-3C will meet on the afternoon of Monday, March 12. The committee will discuss reports from members of the committee on individual assignments studied during the past year.

**Unit Committee T-3D—Instruments for Measuring Corrosion**

Unit Committee T-3D will meet on the morning of Tuesday, March 13. The committee will discuss use of instruments used for measuring corrosion. It is expected a report from the task group on Electrical Holiday Inspection of Coatings will be ready for discussion at the meeting.

**Unit Committee T-3E—Railroads**

Unit Committee T-3E will meet Wednesday, March 14. Two task groups of the committee on railroad tank cars and railroad hopper cars will meet following the T-3E meeting. Reports of progress will be made by the task groups. There will be a discussion of the Railroad Corrosion New Letter issued by the committee and railroad corrosion problems in general.

**Unit Committee T-3F—Corrosion by High Purity Water**

Unit Committee T-3F will meet on the afternoon of Wednesday, March 14. T-3F currently is engaged in gathering as much unclassified information on corrosion by high purity water as possible. As part of the committee work T-3F is sponsoring a symposium as part of the technical program at the conference. Papers scheduled for presentation at the symposium are: The Corrosion of Iron in High Temperature Water, by D. L. Douglas, F. J. Shipko and F. C. Zyzes, Knolls Atomic Power Laboratory, Schenectady, N. Y.; Corrosion Studies in High Temperature Water by a Hydrogen Effusion Method, by M. C. Bloom and M. Crulfield, Naval Research Laboratory, Washington, D.C.;

(Continued on Page 86)

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## Many Topics Listed—

(Continued from Page 84)

Corrosion Resistant Aluminum Alloys for Use in Water at Elevated Temperatures, by J. D. Draley, Argonne National Laboratory, Lemont, Illinois; Aluminum Alloys for Handling High Purity Water, by W. W. Binger and C. M. Marstiller, Aluminum Company of America, New Kensington, Pennsylvania; Corrosion of Stainless Steels in Supercritical Water, by H. A. Pray and W. K. Boyd, Battelle Memorial Institute, Columbus, Ohio.

**Unit Committee T-3G—Cathodic Protection**

Unit Committee T-3G will meet on the morning of Tuesday, March 13. The meeting of T-3G will consist of a discussion of cathodic protection as applied to structures other than pipe lines and utilities.

**Unit Committee T-3H—Tanker Corrosion**

Unit Committee T-3H will meet on the afternoon of Tuesday, March 13. Various aspects of tanker corrosion and its control will be discussed by members of the committee. Several members have been asked to present their experiences on the subject.

**Unit Committee T-4A—Effects of Electrical Grounding on Corrosion**

Unit Committee T-4A will meet on the afternoon of Tuesday, March 13. Grounding practices and their effect on corrosion will be discussed. The scope of this committee has been changed and is now to make recommendations for utility grounding practices for optimum corrosion control. Progress on a bibliography of literature on grounding practices will be reported and discussed.

**Unit Committee T-4B—Corrosion of Cable Sheaths**

Unit Committee T-4B and its six task groups will meet all day Tuesday, March 13. Task groups on Lead and Other Metallic Sheaths, Cathodic Protection, Tests and Surveys, Protection of Pipe Type Cables, Non-Metallic Sheaths and Coatings and Stray Current Electrolysis will report on progress made in 1955. Task groups of this unit committee have many projects under study and at least two interim reports are being made ready for publication.

**Unit Committee T-4D—Corrosion by Deicing Salts**

Unit Committee T-4D will meet on the afternoon of Monday, March 12. A task group assigned to study and develop procedures for conducting field tests above ground will report. Another task group will report on progress made on a study to develop procedures for conducting field tests below ground. The committee will discuss its bibliography on deicing.

**Unit Committee T-4E—Corrosion by Domestic Waters**

Unit Committee T-4E will meet on the afternoon of Tuesday, March 13. The committee has been making an inventory of actual use specimens with an accompanying record of conditions of use, water analysis and type of metal. Contributions to the inventory to date and plans for future work will be discussed at the meeting.

**Unit Committee T-4F—Materials Selection for Corrosion Mitigation in the Utility Industry**

Unit Committee T-4F will meet on the morning of Monday, March 12. Two chairmen of this committee have been forced to resign because of other business this year. As a result the committee has not conducted much business. An effort will be made to organize work at the meeting.

**Unit Committee T-5A—Chemical Manufacturing Industry**

Unit Committee T-5A will meet on the afternoon of Monday, March 12. This committee will hear reports of progress from task groups on sulfuric acid, acetic acid, chlorine, nitric acid, and corrosion by hydrogen flouride. The task group on chlorine has recently completed a bibliography on chlorine that includes 86 abstracts. It is expected the bibliography will be published in the near future.

**Unit Committee T-5B—High Temperature Corrosion**

Unit Committee T-5B will meet on the morning of Tuesday, March 13. Recent developments in high temperature corrosion will be discussed. Task Group T-5B-2 on Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry will report progress. This task group will hold two meetings. One will be on the afternoon of Monday, March 12 and the second on the morning of Friday, March 16. It is expected members of the task group will come prepared to relate experiences and methods of control. Several papers on the subject will be presented at the Refinery Industry and High Temperature Symposia by members of the task group.

**Unit Committee T-5D—Plastic Materials of Construction**

Unit Committee T-5D will meet on the morning of Tuesday, March 13. Eight task groups of the unit committee will report on progress made on specific assignments. The task groups are on questionnaires, inorganic acids, inorganic alkalies, gases, water and salt solutions, organic chemicals, engineering design and methods and criteria for evaluating plastics in chemical environment. A summary of replies to the questionnaire circulated by the committee earlier this year will be given.

**Unit Committee T-5E—Stress Corrosion Cracking of Austenitic Stainless Steel**

Unit Committee T-5E will meet on the morning of Thursday, March 15. This committee was organized at a meeting in Houston October 18. Committee projects will be outlined and discussed.

**Unit Committee T-6A—Organic Coatings and Linings for Resistance to Atmospheric Corrosion**

Unit Committee T-6A will meet on the afternoon of Monday, March 12. The committee will discuss progress reports from task groups on heavy linings, vinyl coatings, vinylidene chloride polymers, phenolics, polyethylene, rubber and elastomers, silicones, methyacrylates furanes, polyesters, epoxies and fluorocarbons.

**Unit Committee T-6B—Protective Coatings for resistance to Atmospheric Corrosion**

Unit Committee T-6B will meet on the morning of Tuesday, March 12. The committee will continue to work on a chart designed to give the properties of various protective coatings used for protection against atmospheric corrosion.

**Unit Committee T-6C—Protective Coatings for Resistance to Marine Corrosion**

Unit Committee T-6C will meet on the morning of Wednesday, March 14. The committee will discuss results of tests

(Continued on Page 87)

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## Many Topics Listed—

(Continued From Page 86)

being conducted on coatings for resistance to marine corrosion.

**Unit Committee T-6E—Protective Coatings in Petroleum Production**
Unit Committee T-6E will meet on the morning of Thursday, March 15. Experience on the use of various protective coatings in petroleum production will be discussed by members of the committee.

**Unit Committee T-6G—Surface Preparation for Organic Coatings**
Unit Committee T-6G will meet on the morning of Thursday, March 15. The committee will discuss the ASTM specification for the surface preparation of aluminum for coating. Future work for the committee will be discussed.

**Unit Committee T-6H—Glass Linings and Vitreous Enamels**
Unit Committee T-6H will meet on the morning of Wednesday, March 14. The committee will discuss the use of glass linings and vitreous enamels for protection against corrosion.

**Unit Committee T-6K—Corrosion Resistant Construction with Masonry and Allied Materials**
Unit Committee T-6K will meet on the morning of Thursday, March 15. It is expected a report will be made to the committee on masonry shape, sizes and costs including illustrations, hollow and glazed tile, red shale and fire clay brick, carbon brick and temperature and corrosion resistance up to 2000 F. Another report is expected on the chemical resistance of reinforced concrete to corrosion.


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# High Temperature Sulfide Corrosion Session Lasts Day

So much interest was exhibited by those attending the October 19 meeting of Task Group T-5B-2 on Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry that the session was continued for a full day. Fifty representatives from many of the country's large refineries, besides refinery builders and equipment manufacturers were present.

Experiences with sulfide corrosion at high temperatures and pressures in refinery equipment was related by several committee members present. One member showed colored slides that illustrated very clearly the type of scale formed on the outside surface of heat exchanger tubes and the manner in which it can flake off. It was reported the scale was 1/64-inch thick, consisted of four layers and had developed in seven months' operation. The 1/64-inch thick scale represented a corrosion rate of approximately 0.02-inch per year. The scale was nonmagnetic and had formed in streams containing about 0.02 percent hydrogen sulfide by volume. It was said the scale does not flake off readily during operation but when a unit has been shut down and is started again the scale tends to break off and plug the units.

### Scale Under Compression

Characteristics of the scale were further illustrated by exhibition of a short section of a 2.25 percent chromium-1 percent molybdenum heater tube containing a tight, dense scale about ¼-inch thick on the inside. This was estimated to represent a metal loss of about 1/16-inch. When the section had been slit by cutting down to the scale, the ring sprang apart indicating the scale had been in compression. This was offered as an explanation of why the scale remained in place. Careful examination revealed that the scale consisted of 21 layers. It was thought a layer formed with each major temperature change. This sample was from a primary heater that had operated four years at 850-950 F fluid temperature. Estimated metal temperature was 1100 F and recycled gas was in the stream. Initial corrosion rates of 0.5-inch per year were indicated on the basis of a run of several months. However, the scale proved to offer protection. This resulted in a tolerable corrosion rate over longer periods of time.

The paper "High Temperature Hydrogen Sulfide Corrosion," by E. B. Backensto, R. E. Drew and C. C. Stapleford of Socony-Mobile Laboratories in Paulsboro, New Jersey was used as the basis of discussion by the committee. This paper is published in the Technical Section of this issue of Corrosion.

### Hydrogen Diffusion Considered

Subjects discussed by the committee included hydrogen diffusion into steel, increase of chromium content at the surface caused by diffusion of iron out into the corrosion product, experience and test results with aluminum coatings of different types, conditions under which the formation of iron sulfide has been observed, use of desulfurizers to reduce the amount of hydrogen sulfide in reforming units, why sulfide corrosion has not been previously experienced in refining sour crudes, a graph showing maximum corrosion rates on different stock at temperatures of 900 and 760 F plotted versus hydrogen sulfide concentrations, instruments and testing techniques, tests being run on various alloys, aluminum coatings of steel in the aircraft industry and the need for a determination of the type of information the refineries should develop, methods for testing and analysis and a uniform reporting procedure so that accurate comparisons can be made with respect to sulfur, hydrogen and hydrogen sulfide contents of feed stocks.

The next meeting of the committee will be held in New York during the annual NACE Conferene next March 12-16. It has been suggested that members come prepared to present a discussion of information on the subject.

## Utilities Industry Unit Seeks More Members

Technical Unit Committee T-4F on Materials Selection for Corrosion Mitigation in the Utilities Industry is seeking members from the electric, gas, steam, water and communication industries. Subjects suggested for study by the committee include selection of materials for pumps, valves, steam condensers, traveling screens, meters and other structures in submerged water; selection of alloy steels for equipment and piping exposed to corrosive atmospheres; selection of metals and alloys for ground rods, capacitor cases, overhead lines and other components of electrical systems.

F. E. Kulman, Consolidated Edison Company of New York, N. Y., chairman of the Group Committee T-4 on Corrosion in the Utility Industry hopes the membership of the committee can be expanded to include members from all the utility fields and all sections of the country. It is expected that a new chairman and vice chairman will be selected after the membership has been expanded and committee work defined. Any NACE member interested in learning more about this commiteet or in becoming a member is urged to write T. J. Hull, NACE, 1061 M & M Building, Houston 2, Texas.

## Railroad News Letter

The October, 1955 issue of the Railroad Corrosion News Letter, a contribution by NACE T-3E on Corrosion Control in the Transportation Industries has been distributed. The issue of No. 2 of Volume 3 of the publication. S. K. Coburn, who is with the Association of American Railroads, Chicago, is editor.

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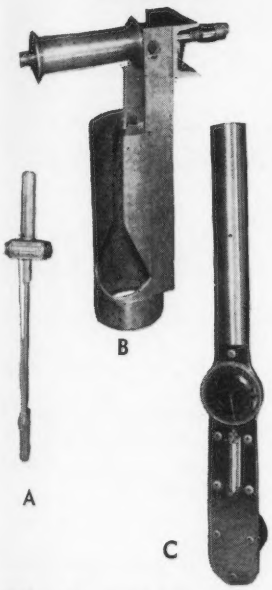
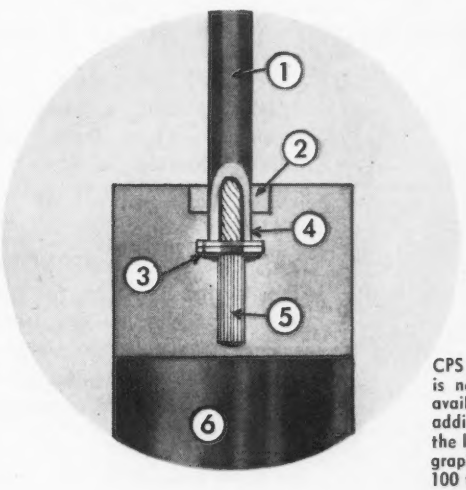
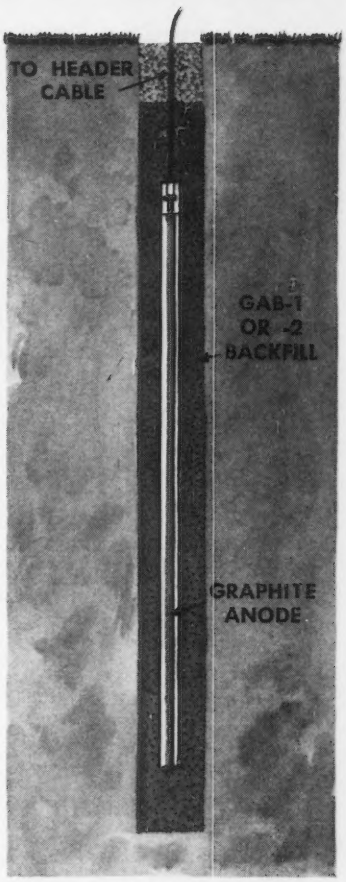



THE Above shows testing devices used on CPS graphite anodes to determine permanency of lead wire attachment. (A) Non-destructive minimum 300 lb. setting wrench. (B) "Torkflash" testing device developed by CPS to assure quality control of lead-wire attachment, (C) Indicating destructive tester.

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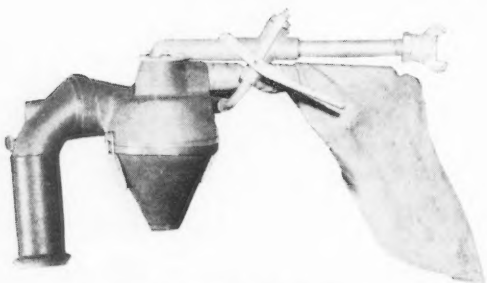

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PORT ARTHUR—Duckworth Supply Co., Inc., P. O. Box 208 YU 2-1901
SAN ANTONIO—Askew Equip. Co., 1111 Humble Ave. WA 3-4396

**LOUISIANA**

NEW ORLEANS—Welding & Mfg. Co., P. O. Box 264 RA-2543
SHREVEPORT—Peerless Supply Co., Inc., 701 Spring St. 4-1451

**OKLAHOMA**

OKLAHOMA CITY—Herd Equipment Co., 922 N.W. 5th St. CE 2-2151
TULSA—Herd Equipment Co., 5324 E. Admiral St. 85-1991
WOODARD—Herd Equipment Co., 1124 W. Main St. 475

**MISSISSIPPI**

NATCHEZ—Peerless Supply Co., Inc., 200 State St. 1158-9

**AREA REPRESENTATIVE**

**E. W. OAKES, 6815 Montrose St., Houston 17**
**OR 4-2612**

# Triple Simultaneous Sessions Set for New York

## Six Symposia Set for San Antonio Meeting

Six symposia have been scheduled tentatively for the October 23-26, 1956 meeting of South Central Region in San Antonio. Norman Hackerman, University of Texas, Austin and John D. Sudbury, Continental Oil Co., Ponca City, Okla., co-chairmen of the technical program committee announced the following symposia are under consideration: Corrosion in the Utilities Industries, Elevated Temperature Corrosion, Corrosion in the Transportation Industry, Pipe Line Corrosion and Corrosion in Oil and Gas Well Equipment.

## Committeemen Are Named For Oct. 23-26 Sessions

Alamo Section has completed preliminary planning for the 1956 South Central Region meeting in San Antonio, Texas. It is scheduled for October 23-26 at the Gunter Hotel. Joseph W. Gibson, D. W. Haering & Co., Inc., San Antonio, General Arrangements Committee chairman named members of his committee as follows:

W. W. Elley, Southwestern Bell Telephone Co., San Antonio, local arrangements.

Norman Hackerman, University of Texas, Austin, technical program.

John D. Sudbury, Continental Oil Company, Ponca City, Okla., technical program.

Max F. Schlather, United Gas Pipe Line Company, San Antonio, finance.

Herschel C. McDonald, United Gas Pipe Line Company, San Antonio, finance.

David N. Henry, United Gas Pipe Line Co., San Antonio, entertainment.

Mdms. W. W. Elley and Max F. Schlather, ladies' program.

Paul V. Sanders, D. W. Haering & Co., Inc., San Antonio, publicity and printing.

Philip S. Donnell, City Water Board, San Antonio, publicity and printing, San Antonio.

Carl M. Thorn, Southwestern Bell Telephone Co., San Antonio, properties and communication.

C. R. Goodrich, consultant, San Antonio, field trips and transportation.

**TECHNICAL PROGRAM**

**MONDAY—March 12**
- Committee meetings all day.

**TUESDAY—March 13**
- Business Meeting
- Corrosion Principles Symposium
- Chemical Inhibitor Symposium
- Refinery Industry Symposium (Part 1)
- Oil and Gas Production Symposium
- High Purity Water Symposium
- Educational Lecture

**WEDNESDAY—March 14**
- Chemical Industry Symposium (Part 1)
- General Pipe Line Symposium
- Steel Metallurgy and Corrosion
- Chemical Industry Symposium (Part 2)
- Power and Communications Symposium
- Pipe Line Group Discussions
- Educational Lecture

**THURSDAY—March 15**
- Cathodic Protection Symposium
- Plastics Symposium
- Refinery Industry Symposium (Part 2)
- Elevated Temperature Symposium
- Protective Coatings Symposium
- Worldwide Developments in Corrosion
- Educational Lecture

**FRIDAY—March 16**
- General Corrosion Round Table
- Pipe Line Underground Round Table

## Niagara Frontier Section Elects Officers for 1956

Elected as officers of the Niagara Frontier Section to take office January 1, 1956 are J. M. Fouts, Chairman; New York Tel. Co., Buffalo 8, New York; E. H. Caldwell, Vice Chairman; Oldbury Electrochemical Company, Niagara Falls, New York; Walter A. Szymanski, Secretary-Treasurer; Hooker Electrochemical Co., Niagara Falls, New York.

## Corpus Christi Section

Charles J. Fritts, Socony Paint Products Co., Houston was the scheduled speaker at a November meeting of Corpus Christi Section. His topic was Corrosion Control on Offshore Drilling and Producing Equipment.

Zane V. Morgan — Top Academy Lieutenant, Jet

## NOTICE ON PAYMENT OF 1956 NACE DUES

**Invoices for 1956 membership dues have been sent to all Active and Junior NACE members. These dues are payable January 1, 1956. The NACE by-laws state that no member with dues in arrears for three months shall receive the publications of the association until such dues are paid.**

***• Accordingly the names of Active and Junior members whose 1956 dues have not been received by March 30, 1956 will be removed from the mailing list to receive CORROSION. No mailings of CORROSION will be made to delinquent members until dues are paid.***

## *Technical Program to Set Record With Over 60 Papers Scheduled*

Triple simultaneous sessions will be the rule for two and one-half days of the technical program to be given during the NACE Twelfth Annual Conference and Corrosion Show at New York. Morning programs March 13 and March 16 will feature double sessions. This will be the first time triple sessions have been held at a NACE national conference.

A preliminary list shows that 62 papers are scheduled. W. Z. Friend, The International Nickel Co., Inc., New York said three or four more papers are still to be committed. If these are received, the number of technical papers scheduled for the 1956 conference will be more than 40 percent greater than the number presented at any previous NACE national conference.

Also included in the program are round table discussions on pipe line and underground corrosion and general corrosion problems and the usual pipe line group discussions. Three educational lectures are included among the 62 titles listed by Mr. Friend. These latter have drawn capacity audiences at other NACE meetings.

The tentative program released by Mr. Friend for publication is:

**Educational Lectures on Fundamentals**

Chairmen: Franklin H. Beck, Ohio State University, Columbus and J. J. Harwood, Office of Naval Research, Washington, D. C.

No. 1—A Fundamental Approach to the Mechanism of Corrosion Inhibition, Norman Hackerman, University of Texas, Austin.

No. 2—The Relation of Thin Films to Corrosion by T. N. Rhodin, E. I. duPont de Nemours & Co., Inc., Wilmington, Del.

No. 3—Effects of Velocity on Corrosion by H. R. Copson, The International Nickel Co., Inc., Bayonne, N. J.

**Corrosion Principles Symposium**

Chairmen: R. B. Hoxeng, Applied Research Laboratory, United States Steel Corp., Monroeville, Pa. and W. A. Luce, The Duriron Co., Dayton, Ohio.

Fretting Corrosion, H. H. Uhlig, Massachusetts Institute of Technology, Cambridge.

Corrosion Fatigue, Israel Cornet, University of California, Berkeley.

**Chemical Inhibitor Symposium**

Chairmen: J. L. Wasco, The Dow Chemical Company, Midland, Mich. and George E. Best, Mutual Chemical Division, Allied Chemical and Dye Corp., Baltimore, Md.

Electrical Resistance Corrosion Measurements Employing Alternating Currents, W. L. Denman, Dearborn Chemical Co., Chicago.

(Continued on Page 93)

Fair

Stewart

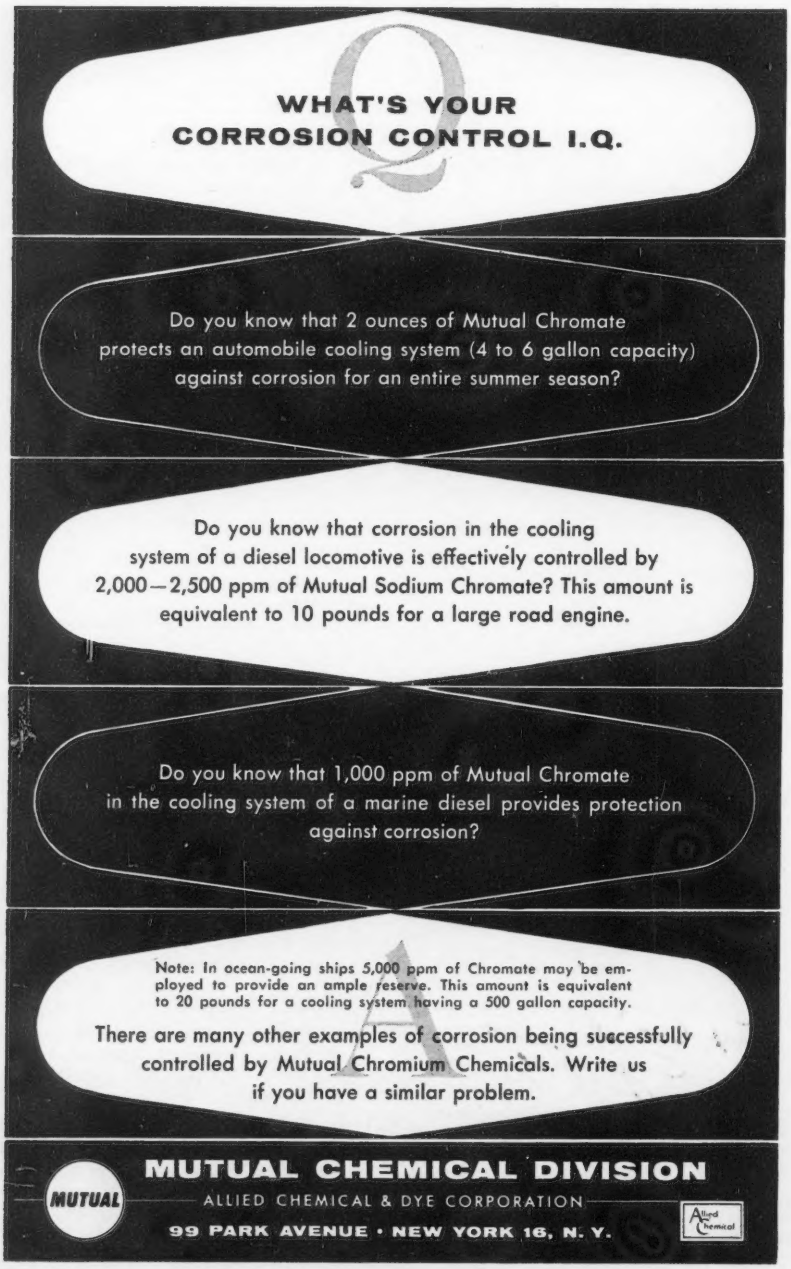
Brannon

Bilhartz

Hamilton

Stegner

# New NACE Officers and Directors Are Named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## *More Than 2000 Valid Ballots Are Cast in Election*

Tellers counted 2188 valid and 30 invalid ballots from members of the National Association of Corrosion Engineers in the election of new officers for 1956-57. Elected were W. F. Fair, Jr., Tar Products Div., Koppers Co., Inc., Pittsburgh, president; W. H. Stewart, Sun Pipe Line Co., Beaumont, Texas, vice-president and R. A. Brannon, Humble Pipe Line Co., Houston, treasurer.

Mr. Fair is the 1955-56 vice-president and Mr. Brannon was reelected treasurer for the fifth time.

Also elected were three directors, H. L. Bilhartz, Production Profits, Inc., Dallas, representing corporate members; Hugh L. Hamilton, The A. V. Smith Engineering Co., Narberth, Pa. and A. L. Stegner, Tennessee Gas Transmission Co., Houston, representing active members.

All take office March 16, the last day of the 1956 Twelfth Annual Conference.

Mr. Fair was a director representing active membership for the three-year term 1953-56 when he was elected vice-president. Mr. Stewart, a director representing active membership for the period 1955-58 will vacate the directorship when he takes office as vice-president. His successor will be named March 16.

Mr. Brannon, who was reelected for a fifth consecutive term as treasurer, was the first president of NACE. In addition to his administrative work he is active in technical committees and in regional and sectional activities.

H. L. Bilhartz, a frequent contributor of technical material to Corrosion, active in NACE technical committees and frequently a speaker before section meetings, was chairman of the technical program committee for the 1955 NACE Conference.

Hugh L. Hamilton, who has been section and region chairman, active in technical committee work and in other ways is well known because of his long activity in the pipeline field. He is one of the early members of NACE and has done much to further its growth.

A. L. Stegner, who almost always turns up doing a lot of work in connection with the pipeline activities of NACE, especially at regional and national meetings, has held sectional offices and presented technical papers at meetings.

## Technical Program –

(Continued From Page 91)

Inhibiting Corrosion of Steel, Aluminum and Magnesium Intermittently Exposed to Brines, George E. Best and John W. McGrew, Mutual Chemical Division, Allied Chemical and Dye Corp.

Laboratory Evaluation of Corrosion Inhibitors by R. A. Marsh, Pure Oil Co. Research Laboratories, Crystal Lake, Ill.

### Refinery Industry Symposium

Chairmen: R. J. Hafsten, Standard Oil Company (Ind.), Whiting, Ind. and J. F. Mason, Jr., The International Nickel Co., Inc., New York.

How Richfield Tackled Hydrogen Blistering in Its New Fluid Catalytic Cracking Unit, B. W. Neumaier and C. M. Schillmoller, Richfield Oil Corp., Wilmington, Cal.

A Refinery Paint Program to Cut Maintenance Costs by R. J. Hafsten, H. A. Homan and K. R. Walson, Standard Oil Co. (Ind.), Whiting, Ind.

Electrical Resistivity Technique for Evaluation of Corrosion Inhibitors in Light Hydrocarbons, W. L. Lewis, Esso Standard Oil Co., Baton Rouge, La.

Collection and Correlation of High Temperature Hydrogen Sulfide Corrosion Data by G. Sorrell, M. W. Kellogg Co., New York.

A paper dealing with naphthenic acid corrosion at N. V. de Bataafsche Petroleum Maatschappij, Netherlands, P. D. Thomas, Asiatic Petroleum Co., New York.

A paper dealing with hydrogen chloride evolution from crude oils by G. J. Samuelson, Petrolyte Corp., St. Louis, Mo.

A paper on tests of corrosion by hydrogen sulfide and hydrogen in operating units by E. B. Backensto and others, Socony Mobil Oil Co., Paulsboro, N. J.

### Oil and Gas Production Symposium

Chairmen: W. F. Oxford, Jr., Sun Oil Co., Beaumont, Texas and J. L. Battle, Humble Oil and Refining Co., Houston.

Concentration Cell Corrosion of Well Casing Joints, author to be named.

Cathodic Protection of Oil Well Casing in Western Kansas by W. C. Koger, Cities Service Oil Co., Bartlesville, Okla.

Cathodic Protection of Mobile Offshore Drilling Platforms, E. P. Doremus, Cathodic Protection Service, Houston.

### High Purity Water Symposium

Chairmen: A. H. Roebuck, Continental Oil Co., Ponca City, Okla. and R. U. Blaser, The Babcock and Wilcox Co., Alliance, Ohio.

The Corrosion of Iron in High Temperature Water by D. L. Douglas, F. J. Shipko and F. C. Zyzes, Knolls Atomic Power Laboratory, Schenectady, N. Y.

Corrosion Studies in High Temperature Water by a Hydrogen Effusion Method by M. C. Bloom and M. Crulfield, Naval Research Laboratory, Washington, D. C.

Corrosion Resistant Aluminum Alloys for Use in Water at Elevated Temperatures by J. D. Draley, Argonne National Laboratory, Lemont, Illinois.

Aluminum Alloys for Handling High Purity Water by W. W. Binger and C. M. Marstiller, Aluminum Company of America, New Kensington, Pa.

(Continued on Page 95)


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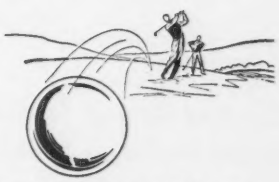

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# Fontana and Hackerman to Receive NACE Awards

## *Two Teachers, Both Active in NACE, Selected for Honors*

Two educators with a long record of activity in corrosion mitigation both in the National Association of Corrosion Engineers and other organizations doing corrosion control work have been selected to receive the 1956 NACE Awards. The 1956 Whitney Award will go to Norman Hackerman, professor of chemistry, University of Texas and the 1956 Speller Award to Mars G. Fontana, professor of metallurgical engineering, Ohio State University, Columbus.

Both honorees became members of NACE in 1946. Dr. Fontana has more than 23 years of corrosion work behind him and Dr. Hackerman, 16.

Presentation of the awards will be at the annual banquet to be held at Hotel Statler, New York City during the March 12-16 NACE Twelfth Annual Conference.

Dr. Fontana, NACE president 1952-53, chairman of the NACE Technical Practices Committee 1950-51, has a PhD in metallurgical engineering from University of Michigan, 1934. Besides being professor of metallurgical research, Engineering Experiment Station, Ohio State University, he is consultant for several metallurgical companies.

He has authored and co-authored a lengthy list of articles.

Dr. Hackerman was named chairman of the chemistry department of the University of Texas in 1953, where he also is director of the Corrosion Research Laboratory and professor of chemistry. Holding a PhD from Johns-Hopkins, 1935, he taught at Loyola College, Baltimore and Virginia Polytechnic Institute before going to the Manhattan Project in 1944 as research chemist. He has been at the University of Texas since 1945.

He has been active in NACE as a member of the board of directors, as chairman of the NACE Education Committee and organized and conducted the 1949 University of Texas-NACE Short Course on Corrosion. He also is first vice-president of The Electrochemical Society and was technical editor of the society's journal in 1953.

Fontana

Hackerman

### MARS G. FONTANA

Dr. Fontana is now professor of metallurgical engineering at Ohio State University and professor of metallurgical research, Engineering Experiment Station, Ohio State University, Columbus. His experience in corrosion work covers 23 years, including two years of high temperature research, 11 years as a metallurgical engineer with E. I. duPont de Nemours & Co., Ltd., Wilmington, Del., consultation work for duPont, Duriron Company and others.

He has a BS in chemical engineering (1931); MS in metallurgical engineering (1932) and PhD in metallurgy (1934) all at University of Michigan.

A member of NACE since April 22, 1946, he was vice-president in 1951-52 and president 1952-53. He has been active in association affairs in administrative and technical capacities and has contributed technical material for publication in CORROSION. He was chairman of the NACE Technical Practices Committee in 1950-51.

His voluminous contributions to the technical literature on corrosion include contributions as editor of the corrosion department of Industrial and Engineering Chemistry.

### NORMAN HACKERMAN

Dr. Hackerman, now chairman of the chemistry department of University of Texas, Austin, also is professor of chemistry at the university and director of its Corrosion Research Laboratory. His 16 years of corrosion work include a year of research at the United States Coast Guard Base, Staten Island, N. Y., three years at Virginia Polytechnic Institute and the remainder at University of Texas. He was assistant chemical professor at Loyola College, Baltimore; research chemist for the Colloid Corp., Baltimore, assistant professor of chemistry at Virginia Polytechnic Institute and went to the Manhattan Project in 1944 as a research chemist. He came to University of Texas in 1945.

He holds a PhD in chemistry from Johns-Hopkins University (1935).

He joined NACE in November, 1946 and has been active in the association ever since. He was technical program chairman for the 1950 Conference and has been chairman of the Education Committee for several years. In this capacity he has helped select the author to receive the annual Young Author award. He has been a frequent contributor of technical material, principally on theory of inhibitors, galvanic processes and anerobic corrosion.

He was technical editor for the Journal of The Electrochemical Society in 1953 and first vice-president of the society in 1954-55.

## Greater Boston Section Hears Nicholas J. Grant

The roles of alloy composition, surface protection and environmental factors were stressed by Nicholas J. Grant, Associate Professor in the Department of Metallurgy, Massachusetts Institute of Technology at a meeting of Greater Boston Section December 7. Prof. Grant's topic was "High Temperature Catastrophic Corrosion of Metals."

Prof. Grant, who is doing research in physical chemistry of steel making and high temperature effects is or has been a member of the National Advisory Committee for Aeronautics, the Titanium Advisory Board of the U. S. Army Ordnance Corps and the Metallurgical Advisory Board for Oak Ridge National Laboratory's AEC activities.

## Southeast Region Elects New Officers for 1956

The following have been elected as officers of Southeast Region effective January 1, 1956: E. P. Tait, Director; Alloy Steel Products Co., Atlanta, Georgia; Fred D. Stull, Chairman; Texas Gas Trans. Corp., Owensboro, Kentucky; Arthur B. Smith, Vice Chairman; Amercoat Corp., Jacksonville, Florida and R. C. Martin, Secretary-Treasurer; Plantation Pipeline, Atlanta, Georgia.

## Vancouver Has Illustrated Talk on Plastic Materials

R. B. Seymour, Loven Chemical Company, Los Angeles, spoke before some 32 members and guests of the Vancouver Section October 31. Dr. Seymour's lecture "Plastics for Corrosion Resistant Applications" was illustrated with color slides.

Among numerous recent developments, it was pointed out that isocyanates stand out as being the most promising and versatile plastic to come on the market. They have excellent chemical resistance to acids and alkalis, toughness, high gloss, air-curing characteristics, heat resistance, attractive electrical properties and low moisture absorption.

Dr. Seymour said also that these plastics could be used as rigid material, as coatings, or as in foams. However, he stressed the need to recognize the limits of plastic materials and recommended that design of plastic components should be made with full knowledge of mechanical and chemical properties.

## Montreal Section Meets

Bernard Husock, Harco Corp., Cleveland spoke to 25 members of Montreal Section at an October 18 meeting on plant maintenance. Mr. Husock discussed various problems related to corrosion experienced in industrial plants, particularly application of cathodic protection to plant piping and water tanks.

## Carolinas Section Plans 3-Topic, 3-Hour Session For December Meeting

A 3-hour afternoon meeting with three topics scheduled for discussion was held December 9 by Carolinas Section at Celanese Corp. office building, Charlotte, N. C. Dinner at 6 pm followed the technical program.

The program was as follows: Fundamental Principles of Corrosion of Aluminum, D. G. Vandenberg, Research Engineer, Chemical Metallurgy Dept., Aluminum Company of America, New Kensington, Pa. He covered principles of corrosion with emphasis on application to air conditioning equipment, textile plant problems and heat exchanger tubes.

Fundamental Principles of Corrosion of Steel by V. V. Kendall, Corrosion Engineer, National Tube Division, United States Steel Corp., Pittsburgh. Special emphasis was placed on problems encountered in Carolinas Section's area.

Fundamentals of Cathodic Protection, O. W. Wade, Senior Corrosion Engineer, Transcontinental Pipeline Corp., Houston. Cathodic protection problems common to Carolinas industries were covered.

Discussion sessions were held between lectures. John A. Manning, Celanese Corp. of America, Charlotte was moderator of discussions.

•

Abstracts published in the NACE Bibliographic Surveys of Corrosion are obtained from more than 28 abstracting agencies.

## Technical Program –

(Continued from Page 93)

Corrosion of Stainless Steels in Supercritical Water, H. A. Pray and W. K. Boyd, Battelle Memorial Institute, Columbus.

### Chemical Industry Symposium

Chairmen: J. J. Heger, United States Steel Corp., Pittsburgh and B. J. Philibert, Olin-Mathieson Chemical Corp., Baltimore.

Reducing Maintenance Painting Costs in the Chemical Industry, N. L. Monack, H. W. Shockley and J. R. Allen, E. I. duPont de Nemours & Co., Wilmington, Del.

Corrosion of Metals by Liquid Fertilizer Solutions, D. C. Vreeland and S. H. Kalin, United States Steel Corp., Monroeville.

Effect of Metal Cations on the Corrosion of Iron in Acids, H. C. Gatos, MIT, Lexington.

Handling of Acetic Acid, J. A. Manning, Jr., Celanese Corp. of America, Charlotte, N. C.

Stress Corrosion Cracking in Hydrofluoric Acid Solutions, H. R. Copson, The International Nickel Co., Inc., Bayonne, N. J.

Some Studies on Effect of Heat Flux on Corrosion, F. L. Whitney, Jr. and A. O. Fisher, Monsanto Chemical Co., St. Louis.

Application of Statistical Theory of Extreme Values to the Analysis of Corrosion Pit Depth Data by P. M. Aziz, Aluminium Laboratories, Ltd., Kingston, Ont.

Comparison of Alternatives by Capitalized Cost, F. C. Jelen, Solvay Process Div., Allied Chemical and Dye Corp., Syracuse, N. Y.

Estimating Maintenance Painting, R. F. Williams and J. H. Cogshall, Pennsylvania Salt Manufacturing Co., Philadelphia.

A paper by W. D. Robertson, Yale University, New Haven. (Subject to be given.)

### Pipe Line General Symposium

Chairmen: L. G. Sharpe, Napko Paint and Varnish Co., Houston and R. C. Martin, Plantation Pipe Line Co., Atlanta.

Experiments Employing Diatomaceous Earth in Products Pipe Line Filtration, Ivy M. Parker, Plantation Pipe Line Co., Atlanta.

Performance Tests on Pipe Line Coatings, H. W. Wahlquist, Ebasco Services, Inc., New York.

An Outline of Physical Theory of Underground Corrosion, Gordon N. Scott, Los Angeles.

Cathodic Protection of Certain Semi-Marine Pipelines, B. J. Whitley, Jr., Tennessee Gas Transmission Co., Houston.

### Steel Metallurgy and Corrosion

Chairmen: F. J. Radd, Continental Oil Co., Ponca City, Okla.; and F. L. Current, Oil Well Supply Co., Oil City, Pa.

The Role of Iron Carbides and Impurities in the Corrosion of Plain Carbon Steel, D. A. Shock, F. J. Radd, R. L. McGlasson and L. H. Crowder, Continental Oil Co., Ponca City.

Steel Surface Properties Affect Internal Corrosion Performance of Tin Plate Containers, A. H. Willey, American Can Co., Barington, Ill. and J. L. Krikl, American Can Co., Maywood, Ill.

The Influence of Temperature on Corrosion Fatigue, I. Cornet, University of California, Berkeley.

A Statistical Corrosion Fatigue Study of Plain Carbon Steel, F. J. Radd and R. L. McGlasson, Continental Oil Co.

A Study of Galvanic Corrosion, J. T. Waber, Los Alamos Scientific Laboratories, Los Alamos, N. M.

### Power and Communications Symposium

Chairmen: T. J. Maitland, American Telephone and Telegraph Co., New York, N. Y. and W. A. Sinclair, Detroit Edison Co., Detroit, Mich.

Field Laboratory Testing of Wrappings for Buried Structures by H. M. Clayton, Memphis Light, Gas and Water Division, Memphis, Tenn.

Corrosion of Lead Sheathed Power Cables in Concrete Tunnels by R. I. Perry, Commonwealth Edison Co., Chicago, Ill.

Testing Methods and Corrosion Control Measures for Buried Cables by D. R. Werner, American Telephone and Telegraph Co., Kansas City, Mo.

Corrosion Control Equipment for Underground Cables in Conduit in a Stray Current Metropolitan Area by E. P. Teale, American Telephone and Telegraph Co., Washington, D. C.

### Cathodic Protection Symposium

Chairmen: A. L. Ayres, New Jersey Bell Telephone Co., Newark and C. R. Johnson, Port of New York Authority.

Cathodic Protection in Radiant Heating

(Continued on Page 98)


*oil field scale and corrosion engineers*

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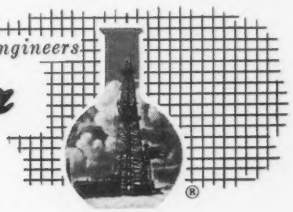

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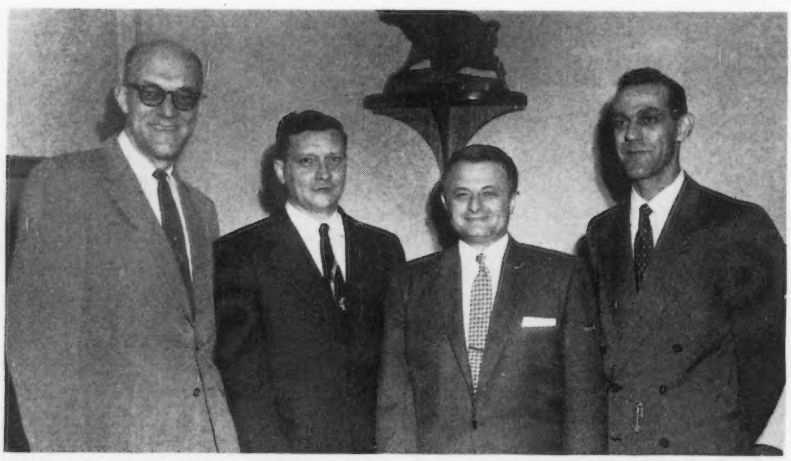

**OFFICERS OF CHICAGO SECTION (top) left to right, V. M. Kalhauge, Standard Oil Co. of Indiana, secretary; R. W. Flournoy, Corn Products Company, chairman; R. B. Janota, Swift and Company, vice-chairman; R. I. Lindberg, Sinclair Research Laboratory, 1954-55 chairman. (Middle) Johns-Manville Sales Corp. hosts, left to right, H. Winiarski, Joseph F. Robin and William L. Breckinridge. (Bottom) left to right, L. W. Ewing, Standard Oil Co. of Indiana, master of ceremonies, and C. G. Munger, Amercoat Corp., South Gate, Cal., principal speaker.**

## *Corrosion and Design Is Topic at Chicago*

"Corrosion and Design" was the subject heard by 72 members and guests of Chicago Section at its November 15 meeting at the Engineer's Club. C. G. Munger, vice president in charge of manufacturing and research for Amercoat Corporation, South Gate, Cal. was the featured speaker.

Basic corrosion problems and the mechanism of rusting were explained by the speaker. Anodic pitted areas usually are acidic with a pH range from 6 to 7 and cathodic areas usually alkaline with pH of 8. Because of this, he poined out, coatings designed to limit corrosion should be both acid and alkaline resistant. Discussion of corrosion on steel structures and methods of coating followed.

L. W. Ewing, Standard Oil Company of Indiana was master of ceremonies. Johns-Manville Sales Corp. was host for the fellowship hour with M. B. Roth as senior host, assisted by J. Robin, W. Breckinridge and H. Winiarski.

## Genesee Valley Section

J. C. Holzworth of General Motors Research Laboratories spoke to a joint meeting of Genessee Valley Section and the Rochester Section, American Society for Metals November 14. The meeting at Howard Johnson's attracted 75 persons from both organizations.

## Gavel Is Presented at Southwestern Ohio Section November 29

Arthur D. Caster, City of Cincinnati, past chairman of Southwestern Ohio Section and Roy O. McDuffie, University of Cincinnati, presented a gavel for use of section chairmen to Al Jenss, Ampco Metal, Inc., chairman at the section's November 29 meeting.

Members of the American Institute of Chemical Engineers who met with the section were introduced individually.

Fifty-nine persons, 21 of them NACE members, were presented for the cocktail hour preceding dinner and to hear Dr. Mars Fontana, Ohio State University speak on "Illustrations of Corrosion."

A tour of the Cincinnati Milling Machine Co. and a motion picture was participated in December 6 by 19 persons of whom 15 were members of Southwestern Ohio Section. A cocktail hour courtesy of the company, followed by dinner preceded the business and technical meeting.

Maurice Weinschelbaum spoke on four groups of materials significant in the manufacture of machine tools. These include cutting fluids, greases, oil, slushes and rust inhibitors. A question and answer period followed.

Santa Claus distributed gifts at the conclusion of the program.

Sol. M. Gleser will address the January 31 meeting on "Causes of Corrosion, Part 1" and William Spurgeon, General Electric Co., on February 28 on "Causes of Corrosion, Part 2."

## Detroit Section Holds First Dinner Meeting

In a first attempt to combine a dinner meeting with the technical portion of the meeting, the November 10 meeing of Detroit Section was attended by approximately 50 members and guests.

Melvin Nord gave a short after-dinner talk on law and engineering correlation problems. C. B. Munger of Amercoat Corporation then spoke on "Linings and Coatings for the Chemical Industry." Mr. Munger's talk covered the problems of application, including surface preparation, stability of product, and adhesion. He supplemented his talk with slides on major points of his speech.

## New Officers Take Over December 1 at Portland

New officers taking over December 1 for Portland Section are: Norman H. Burnett, Huntington Rubber Mills, chairman; R. S. Baynham, Dearborn Chemical Co., vice-chairman and William R. Barber, Jr., Electric Steel Foundry, secretary-treasurer, all of Portland. Mr. Barber was reelected.

Five meetings are planned for Portland Section yearly in January, March, May, September and November, all on the second Thursday of the month. All meetings are held at the Campbell Court Hotel.

Subject of the January 12 meeting is "Aluminum in Corrosive Environments," by a representative of Aluminum Company of America.

# NOW

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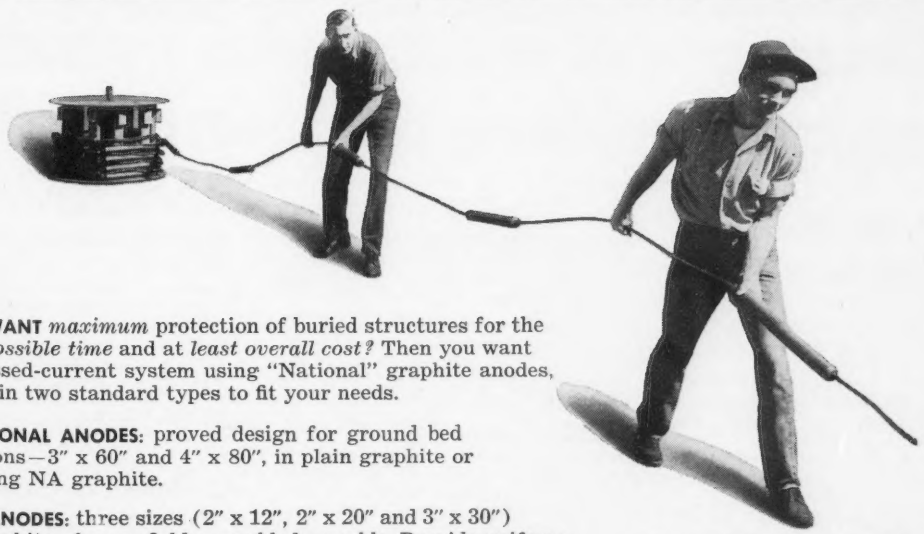

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**TIME OUT FOR A LITTLE DOUGH RAISING** demonstration in the kitchens of the Statler Hotel, New York City was taken by the following working on the program for the March 12-16 Twelfth Annual NACE Conference: (left to right), three assistant chefs; Joseph I. Montel, Hammond-Montel, Inc., Maspeth, N. Y., entertainment and hospitality; R. S. Ashbaugh, Hotel Statler; Alton F. Minor, American Telephone and Telegraph Co., registration and information; Morton Bermann, Brooklyn Union Gas Co., transportation; The Chef; F. J. LeFebvre, Electro Rust-Proofing Corp., local arrangements; H. O. Teeple, The International Nickel Co., Inc., printing; Nelson N. Ehinger, Aluminum Company of America, hotel and meeting rooms; Kenneth H. Roll, Lead Industries Association, general conference chairman; Malcolm W. Riley, Materials and Methods, publicity; F. E. Kulman, Consolidated Edison Company of New York, local arrangements; E. G. Brink, American Viscose Corp., section coordination.

# 30 More Firms Take Space in March 12-16 Corrosion Show at Hotel Statler, New York

Thirty more firms have reserved space in the Corrosion Show to be held concurrently with the NACE 12th Annual Conference at Hotel Statler, New York March 12-16. The 67 firms which have space so far have contracted for 94 booths.

Firms reserving space since the publication of the list in December Corrosion are:

Aluminum Company of America, American Zinc Institute, Inc., Anaconda Wire and Cable Co., Aquaness Corp., Associated Research, Inc.; Barrett Division, Allied Chemical and Dye Corp.; Beryllium Corp., Branson Instruments, Inc.; Stewart R. Browne Mfg. Co.; Cathodic Protection Service, Crane Company, Dow Chemical Company.

The Duriron Company, Electro Rust-Proofing Corp., Good-All Electric Mfg. Company, B. F. Goodrich Company, Haveg Corp.; International Nickel Co., Inc.; Koppers Company, Inc.; Lukens Steel Company, Natasco Company, Nicolet Industries, Inc.; Owens-Corning Fiberglas Corp.; Perrault Equipment Co.; Phelps-Dodge Copper Products Corp.; Pipeline Coating & Engr. Co., Inc.;

Pipe Protection Service, Inc., Royston Laboratories, Inc.; United Chromium Division of Metal and Thermit Corp., T. D. Williamson, Inc.

## Houston Section Plans Six Meetings During 1956

Six meetings have been scheduled by Houston Section during 1956. All except the May picnic meeting will be held at John's Restaurant.

Meetings and topics scheduled are:

January 10—John Watts, Internal Pipeline Maintenance Co. Subject: Internal coatings for pipelines.

February 14—C. G. Munger, Amercoat Corp., South Gate, Cal., Subject: Use of coatings in industry.

March 27—Subject: Protection of underground plant at pump stations.

April 10—H. S. Preiser, Bureau of Ships, U. S. Navy. Subject: Cathodic protection of external ship hulls.

May 8—Picnic.

June 12—Representative of the Magna Co. Subject: Chemical treatment of wells from field and laboratory standpoint.

## Technical Program—

(Continued From Page 95)

Piping, L. C. Wasson, A. O. Smith Corp., Milwaukee.

Lead Cable Sheath Corrosion Under Cathodic Protection Conditions by W. H. Bruckner and R. M. Wainwright, University of Ill.

Protective Criteria of Lead Cable Sheath Under Cathodic Protection, K. G. Compton, Bell Telephone Laboratories, Murray Hill, N. J.

Further Study of Protective Criteria on a Pipe Section in a Uniform Environment, L. P. Sudrabin, Electro Rust-Proofing Corp., Newark, N. J., and F. W. Ringer, Narbeth, Pa.

### Plastics Symposium

Chairmen: R. B. Seymour, Loven Chemical Co. of Cal., Newhall and G. Heinemann, Columbia-Southern Chemical Corp., Corpus Christi, Texas.

Introduction, R. B. Seymour.

Properties and Performance of Thermoplastics in American Industry, J. Malone, B. F. Goodrich Chemical Co., Cleveland and B. H. Philibert, Olin-Mathieson Chemical Corp., Baltimore.

Properties and Performance of Reinforced Polyester Plastics in the Chemical Industry, R. E. Gackenback and D. G. Estey, American Cyanamid Co., Bound Brook, N. J.

Design and Engineering of Plastic Materials of Construction, R. P. Whittier and O. H. Fenner, Monsanto Chemical Co., St. Louis.

### High Temperature Corrosion Symposium

Chairmen: C. C. Harvey, Ethyl Corp., Baton Rouge and W. D. Manly, Oak Ridge National Laboratory, Oak Ridge, Tenn.

Resistance of Metals and Alloys to Corrosion by Fused Sodium Hydroxide by G. Pedro Smith, Mark E. Steidlitz and Eugene E. Hoffman, Metallurgy Division, Oak Ridge National Laboratory, Oak Ridge, Tenn.

Structure of Oxide Scales on Nickel-Chromium Steels by H. J. Yearian, Purdue University, Lafayette, Ind.

Oxidation of Heater Alloys, E. A. Gulbransen, Westinghouse Electric Corp., East Pittsburgh, Pa.

A paper on corrosion by hydrogen sulfide and hydrogen mixtures at high temperatures by C. H. Samans, Standard Oil Co. (Ind.), Whiting, Ind.

### Protective Coatings Symposium

Chairmen: W. P. Cathcart, Tank Lining Corp., Pittsburgh and L. S. Van Delinder, Carbide and Carbon Chemical Corp., South Charleston, W. Va.

Sprayed Metals Plus Plastic Coatings, W. B. Meyer, St. Louis Metallizing Co., St. Louis.

Work Measurement as Applied to Industrial Painting, B. C. Wright, Carbide and Carbon Chemical Corp., Texas City, Texas.

A paper dealing with performance of galvanized coatings sponsored by American Zinc Institute, New York.

### Worldwide Developments in Corrosion

Corrosion by Low Pressure Geothermal Steam. T. Marshall and A. J. Hugill, Dept. of Scientific and Ind. Research, Wellington, N. Z.

Applications of Cathodic Protection in Israel, D. Spector, Tel Aviv.

Corrosion by Differential Aeration and Passivity of Zinc, G. Bianchi, Laboratori di Elettrochimicia del Politechnico di Milano, Milan, Italy.

## Air Pollution Chairman

Lee A. DuBridge, President of California Institute of Technology has been elected chairman of the board of trustees of the Air Pollution Foundation. He is one of the founders of the organization.

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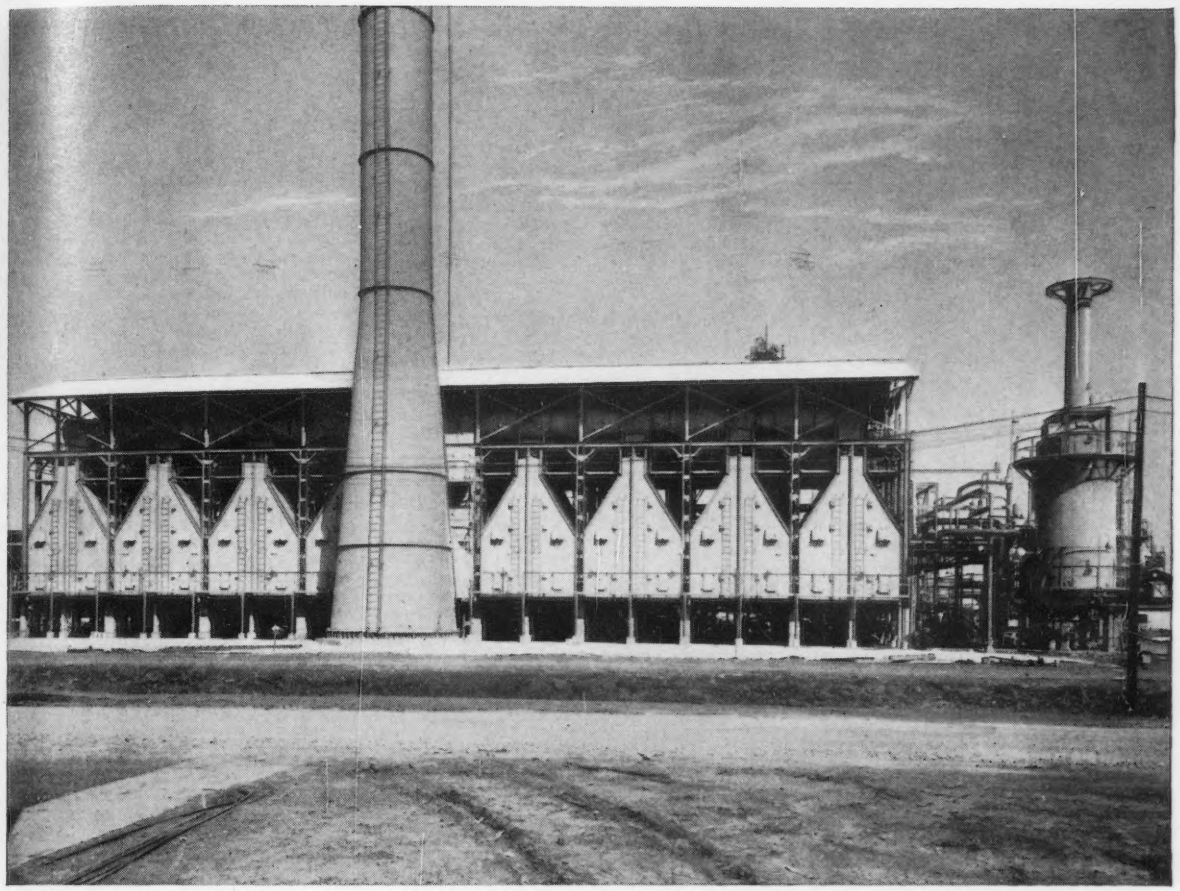
Reprints of technical committee reports of NACE usually are available.



**200 million pounds of Ethylene** can be produced yearly by this bank of eight ethane cracking furnaces at the Tuscola, Illinois plant of National Petro-Chemicals Corporation, (a joint enterprise of National Distillers Products Corporation and Panhandle Eastern Pipeline Company). Largest single installation of its kind to date, these furnaces, operating above 1500F°., produce ethylene by cracking ethane in Incoloy tubes.

# Incoloy tubes perform successfully in hydrocarbon cracking furnaces

The Incoloy* tubes in the ethane cracking furnaces shown above have now given two years satisfactory service — with promise of more to come. Operating temperatures are in excess of 1500°F. A number of installations in other plants have given as much as four years' service in cracking ethane and propane for production of ethylene.

The reasons? Incoloy has high creep and rupture strengths at elevated temperatures. It resists carburization and is stably austenitic. After prolonged exposure to intermediate temperatures, Incoloy shows only slight tendency to become embrittled by carburization and none at all due to structural changes.

You can use Incoloy at temperatures right up to 1800°F. And it gives an improved safety factor in decoking where temporary hot spots may occur.

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In addition to improved performance features, Incoloy also offers a decided price advantage, compared with certain alloys, when it is used as extruded tubing.

Comparatively low thermal expansion and good weldability are other characteristics that make Incoloy an attractive material for this application.

If the severe conditions involved in hydrocarbon cracking or in natural gas reforming are a problem to you, why not consult our High Temperature Engineering Section? They will be glad to help you without cost or obligation.

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## Ffield and Whitney Are Lehigh Valley Section's Technical Speakers

Ffield

Whitney

Outstanding corrosion workers in the United States feature both the November and January meetings of Lehigh Valley Section. Paul Ffield, recently transferred from the Shipbuilding Division of Bethlehem Steel Company at Quincy, Mass. to Bethlehem, Pa. discussed galvanic corrosion at the November meeting. Frank L. Whitney, Jr., Monsanto Chemical Company, St. Louis and president of the National Association of Corrosion Engineers is the featured technical speaker for the January 16 meeting of the section.

The dinner meeting November 21 at Keystone Trail Inn, Allentown, Pa. was attended by 25 members. They heard Mr. Ffield tell some of the history of shipbuilding and the development of awareness of corrosion problems. His talk included much practical information on galvanic corrosion including area relationships, differential aeration, differential velocity and the reaction between dissimilar metals.

## Registration Is 225 at Western Region Meeting

Western Region's November 17-18 Fifth Annual Corrosion Conferenc held at San Francisco was considered by members of the San Francisco Bay Area Section to be an outstanding success. Paid registrations were 225 and there were an estimated 45 or more who attended but did not register formally. The annual banquet, attended by 165 members and guests heard Chester MacPhee, collector of customs for the Port of San Francisco, talk on his experiences as collector of customs.

Wachter

The technical program was held as scheduled with the exception that E. H. Thalmann replaced H. W. Wahlquist of Ebasco Services, Inc. on Friday afternoon. (A complete program was published in December Corrosion, Page 78.)

Aaron Wachter, Shell Development Co., Emeryville, Cal. immediate past-president of the National Association of Corrosion Engineers, received Western Region's distinguished service award.

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Several engineering libraries have complete files of Corrosion and can offer reprint service from their copies.

## Fair Flies Low to Make Baltimore Engagement

W. F. Fair, Jr., Koppers Co., Pittsburgh held Baltimore Section longer than any other speaker—that is, about 30 minutes—which was the length of time he was late for his speaking engagement. Dr. Fair, who reached the Pittsburgh airport on the day of his scheduled evening talk before the Baltimore Section at 1:30 pm only to find his scheduled flight grounded by fog, drove through the rain and fog to Baltimore, arriving only 30 minutes late. Dr. Fair said this was 30 minutes longer than the section waited for any other speaker.

His talk, concerned the technology of coal tar coatings, some factors concerning formulation of a coating for specific applications and methods of application.

### Graphs Show Advantages

He illustrated the advantages of coal tar over other types of coatings with graphs showing moisture absorption over a period of years. There is no relation between flow properties, hardness or softness, he said, advantages of coal tar for underground service including better flow, viscosity and adhesion properties and water resistance.

While cold applied coatings generally are used above ground, hot coatings are preferred for underground service. Undisturbed plasticized enamels will withstand a wide range of temperature changes without cracking, he pointed out. Thixotropic coatings can be applied thickly and have better sealing qualities than filled, emulsion type coatings, he said.

Illustrations included sides of buildings declaired unsafe because of corrosion. A color motion picture of a pipeline installation in Venezuela was shown also in which Dr. Fair acted as producer and cameraman and starred as a pipeline walker.

### Fontana to Talk

Mars G. Fontana, Ohio State University, will talk on "Corrosion: Here There and Aruba" at the February 16 meeting of the section. The dinner meeting will be at the Park Plaza Hotel.

On April 10 Baltimore section will hold a joint meeting with Baltimore-Washington Section of the American Electroplaters Society and The Electrochemical Society. F. L. LaQue, The International Nickel Co., Inc. will be speaker at the session to be held at the National Bureau of Standards in Washington.

W. F. FAIR, JR., Koppers Co., Pittsburgh, center, looks none the worse for wear after his determined automobile trip from Pittsburgh to Baltimore to fill a speaking engagement before Baltimore Section. He was forced to drive when fog grounded his scheduled air flight. At Dr. Fair's left is John F. Oliveira, Bethlehem Steel Co., section chairman and at his right, George E. Best, Mutual Chemical Division, Allied Chemical and Dye Corp., regional chairman.

## Instrumentation for Measurements Is Discussed

Practical design limitations of electrical equipment, types of circuits available and selection of instruments for use in corrosion measurement were discussed at Fort Worth during the December 5 meeting of North Texas Section. Bethel Bond, Cathodic Protection Service, was the speaker on "Instrumentation for Corrosion Measurement" before 19 members and eight guests.

Bond

Officers were elected for 1956 as follows: Edwin H. Muehlhause, Lone Star Gas Co., Dallas, chairman; Monte Kaplan, Atlantic Refining Co., Dallas, vice-chairman and Richard B. Bender, Plastic Engineering & Sales Corp., Fort Worth, secretary-treasurer.

## Teche Section Session

L. V. Musgrove, assistant sales manager, Texsteam Corp., Houston was the scheduled speaker at Teche Section's December 15 meeting at Lafayette. His topic was "Chemical Pumps in Corrosion Control."

## Paint Convention Set

The 1956 Southwestern Paint Convention will be held May 10-21 at Hotel Statler-Hilton, Dallas. Dallas Paint and Varnish Production Club will be host. A technical program, exhibition and social events are planned.

SPEAKERS AT WESTERN REGION'S meeting at San Francisco November 17 and 18: J. R. Cunningham, Standard Oil Co. of California, speaks on Extra Low Carbon Stainless Steels for Chemical Plant and Refining Equipment; middle, left to right, John D. Sudbury, Continental Oil Co. and P. J. Raifsnider, Shell Development Co. during the Oilfield Structures Corrosion Symposium; Preston W. Hill, Signal Oil and Gas Co., speaks on Corrosion Inhibitors for Control of Corrosion in Oil Wells.

## NACE MEETINGS CALENDAR

**Jan.**

5 Pittsburgh Section. Mellon Institute, Oakland, Pa.
9 Philadelphia Section.
9 North Texas Section. At Dallas. What's What in Plastics, W. M. Thornton, Atlantic Refining Co.
10 Schenectady-Albany-Troy Section. At Union College, featuring brief talks on corrosion interests by members.
10 Houston Section. John's Restaurant. John W. Watts, Internal Pipeline Maintenance Co., "Internal Coatings for Pipelines."
17 Chicago Section. Corrosion measurements, C. H. Samans, Standard Oil Research Laboratories.
17 Cleveland Section. Joint meeting with The Electrochemical Society.
17 Genesee Valley Section. Electroless plating, tentative German Club.
19 Sabine-Neches Section. Copper Base Alloys, Al Wafer, Ohmstede Machine Works, Beaumont.
19 Kanawha Valley Section. At Huntington, W. Va. Corrosion Behavior of Aluminum Alloys in Different Environments, Wayne W. Binger, Aluminum Co. of America.
23 Tulsa Section. Protective coatings.
25 Metropolitan New York Section, Chemists Club.
31 Southwestern Ohio Section. Causes of Corrosion, Part 1, Sol M. Gleser, A. M. Kinney Co., Cincinnati. Shuller's Restaurant, Reading, Ohio.

**Feb.**

2 Pittsburgh Section. Mellon Institute.
6 North Texas Section. At Dallas, Cathodic Protection Ground Beds by J. L. Pool, Magnolia Pipe Line Co.
7 Schenectady-Albany-Troy Section. R. C. Ulmer, Combustion Engineering, Inc., "General Corrosion Problems in Industrial and Marine Boiler Operation."
8 Greater Boston Section. Hotel Beaconsfield. Corrosion of Light Metals, R. R. Cope, Aluminum Company of America.
14 Houston Section. John's Restaurant. C. G. Munger, Amercoat Corp., South Gate, Cal., "Use of Coatings in Industry."
15 Genesee Valley Section. Joint meeting with American Institute of Chemical Engineers. Subject: Kel-F Coatings.
21 Chicago Section. Chicago Engineers Club. M. G. Fontana, Ohio State University, "Various Approaches to Corrosion Problems."
21 Cleveland Section. Hotel Manger. Corrosion in Military Installations. Col. Lindsay M. Applegate, U. S. Army Corps of Engineers, Omaha.
23 Sabine-Neches Section. Orange, Texas. Corrosion Problems in High Speed Rotary Compressor, A. D. Hardgroder, Mathieson Chemical Corp., Lake Charles, La.
28 Southwestern Ohio Section. Shuller's Restaurant, Reading, Ohio. Causes of Corrosion, Part 2. Wm. Spurgeon, General Electric Co.

## Cathodic Protection Is Permian Basin Topic

"Cathodic Protection of Steel Oilfield Vessels and Casing Strings," was the topic of F. B. Thorn, Cathodic Protection Service, Houston at the November 14 meeting of Permian Basin Section. He spoke to 17 members and 30 guests at the Lincoln Hotel Odessa.

A report on the Sixth Biennial Corrosion Tour showed total registration was 150. The tour report will be distributed in December or January. Additional copies are available at $2.50 a copy from H. S. Winston, Box 362, Goldsmith, Texas.

Nominations were made for 1956 officers, with elections scheduled by letter ballot during November.

## Sabine-Neches Program

Approximately 36 members and guests attended the December 8 meeting of the Sabine-Neches Section at the Little Mexico Restaurant in Orange, Texas.

A panel consisting of Messrs. C. A. Murray, Pure Oil Company, acting as moderator and Joe Picarazzi, Cities Service Refinery; W. F. Oxford, Jr., Sun Oil Company; Harry Wilton, Texas Company answered questions on refinery corrosion.

The questions covered such items as inhibitors, problems associated with stainless steels, corrosion resistant alloy linings, etc.

Following the discussion it was announced that the next monthly meeting would be on January 19, when copper base alloys will be discussed.

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CSI also offers expert consultation services and a complete line of brand-name cathodic protection materials, including Dow Galvomag and other Dow magnesium anodes. CSI has the trained personnel, power augers and ditching machines to handle your installation requirements.

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# LaJolla Conference On Marine Corrosion Planned April 18-20

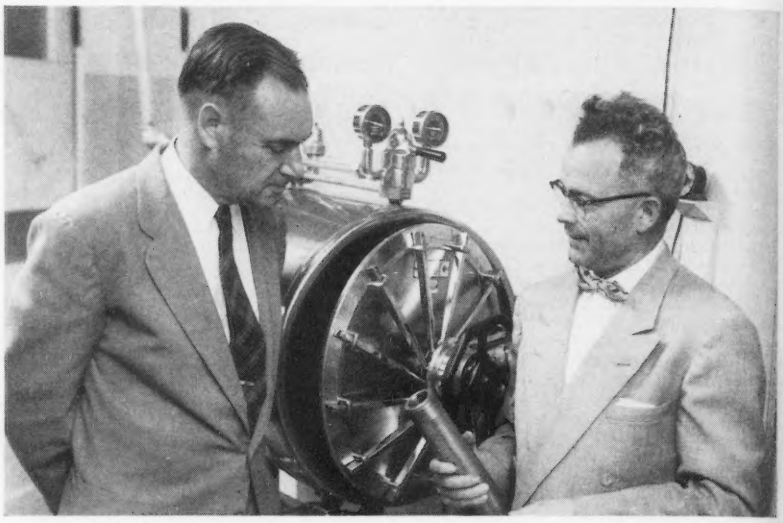
Measures for protection against biological, physical and chemical deterioration of wood, metal and concrete structures will be considered at a conference at LaJolla, California April 18-20. The Conference on Marine Corrosion and Fouling Problems, is sponsored by the Institute of Marine Resources and the Departments of Engineering, University of California, with cooperation of the National Association of Corrosion Engineers' San Diego Section and Western Region. The meeting will be held at the Scripps Institution of Oceanography, La-Jolla.

Members of a planning group have been named as follows: Charles D. Wheelock, Institute of Marine Resources, University of California, general chairman;

Papers Committee: Claude ZoBell, University of California, chairman; L. L. Whiteneck, Long Beach Harbor Dept.; F. O. Waters, San Diego City Water Dept.; I. Cornet, University of California.

Housing and Arrangements Committee: Dallas G. Raasch, LaMesa, Lemon Grove, Spring Valley Irrigation District, La Mesa, Cal., chairman; James Snodgrass, University of California; E. F. Corcoran.

Publicity Committee: J. C. Dillon, University of California, chairman; Harry M. McKee, Nuttall-Styris Cl., San Diego; T. A. Manar and G. A. Lewis, University of California.



**OFFICIALS OF THE CONFERENCE ON MARINE CORROSION and Fouling problems to be held April 18-20 at Scripps Institution of Oceanography, University of California, LaJolla, Cal. are shown inspecting a specimen in the institution's laboratory. Adm. Charles D. Wheelock, left, Institute of Marine Resources, University of California, will be general chairman and Claude ZoBell, right, University of California, chairman of the papers committee. The conference is being given by the Institute of Marine Resources and Departments of Engineering of the university with cooperation of NACE San Diego Section and Western Region.**

## Walker Award Goes to Piret

The AIChE Walker Award has been given to Edgar L. Piret, Professor of Chemical Engineering at the University of Minnesota. He was cited for his excellent publication record, especially in AIChE publications.

## 63 Enroll at Berkeley

Total attendance during the November 14-16 short course on Corrosion Problems in the Process Industries held by University of California, Berkeley with cooperation of Western Region NACE was about 100. There were 63 enrollments, according to I. Cornet, Associate Professor in the college of engineering, who was in charge.

Papers submitted by speakers will be published in the Proceedings of the course. (A complete program was published in October, 1955 Corrosion on Page 76.)

## Lecturers Are Named For Tulsa Pipeliners' Short Course Feb. 15-17

The February 15-17 Seventh Annual Corrosion Control Short Course for Pipeliners will be given by Tulsa Section at the Mayo Hotel, Tulsa. Lectures, demonstrations and discussions of pipeline corrosion and its control will be featured, according to James C. Bell, Service Pipe Line Company, Tulsa, chairman of the section's short course committee.

As in previous courses the instruction is designed for pipeline foremen, superintendents, field engineers and inspectors. Non-technical presentations of the principal aspects of the causes of corrosion, measurements and instrumentation, pipe coatings, galvanic anodes, impressed currents and miscellaneous corrosion control devices are scheduled.

Lecture and discussion periods will be led by J. P. Barrett, Stanolind Oil and Gas Co.; J. R. Cowles, consulting engineer; M. E. Parker, Cormit Engineering Co.; F. M. Hieronymous, Barrett Division, Allied Chemical and Dye Corp.; W. P. McCollister, Mississippi River Fuel Corp.; D. O. Griffith, Shell Pipe Line Corp.; M. C. Callahan, Gulf Refining Co. and I. B. Tietze, Phillips Pipe Line Co.

Registration fee of $15 covers banquet and transportation to demonstration site. Hotel reservations should be made directly. Additional information can be obtained from R. H. Goodnight, Stanolind Oil and Gas Co., Box 591, Tulsa, Okla.

## Paint Technology Course

Houston Paint and Varnish Production Club is sponsoring a protective coatings technology night course at University of Houston. Second semester starts January 20 and may be taken for audit or credit.


**Use "CORECO" Corrosion Rectifiers . . .**
*Designed to Give the Best Results*

"CORECO" systems of corrosion rectification give your pipe lines and storage tank bottoms, offshore lines and marine installations better protection through better engineering.

The results? Less maintenance, lower labor costs, longer life for the metal. Learn how "CORECO" can serve you! Check the reprints you want SENT TO YOU FREE, clip this advertisement and mail it with your name and address to: CORECO, 1506 Zora Street, Houston, Texas.

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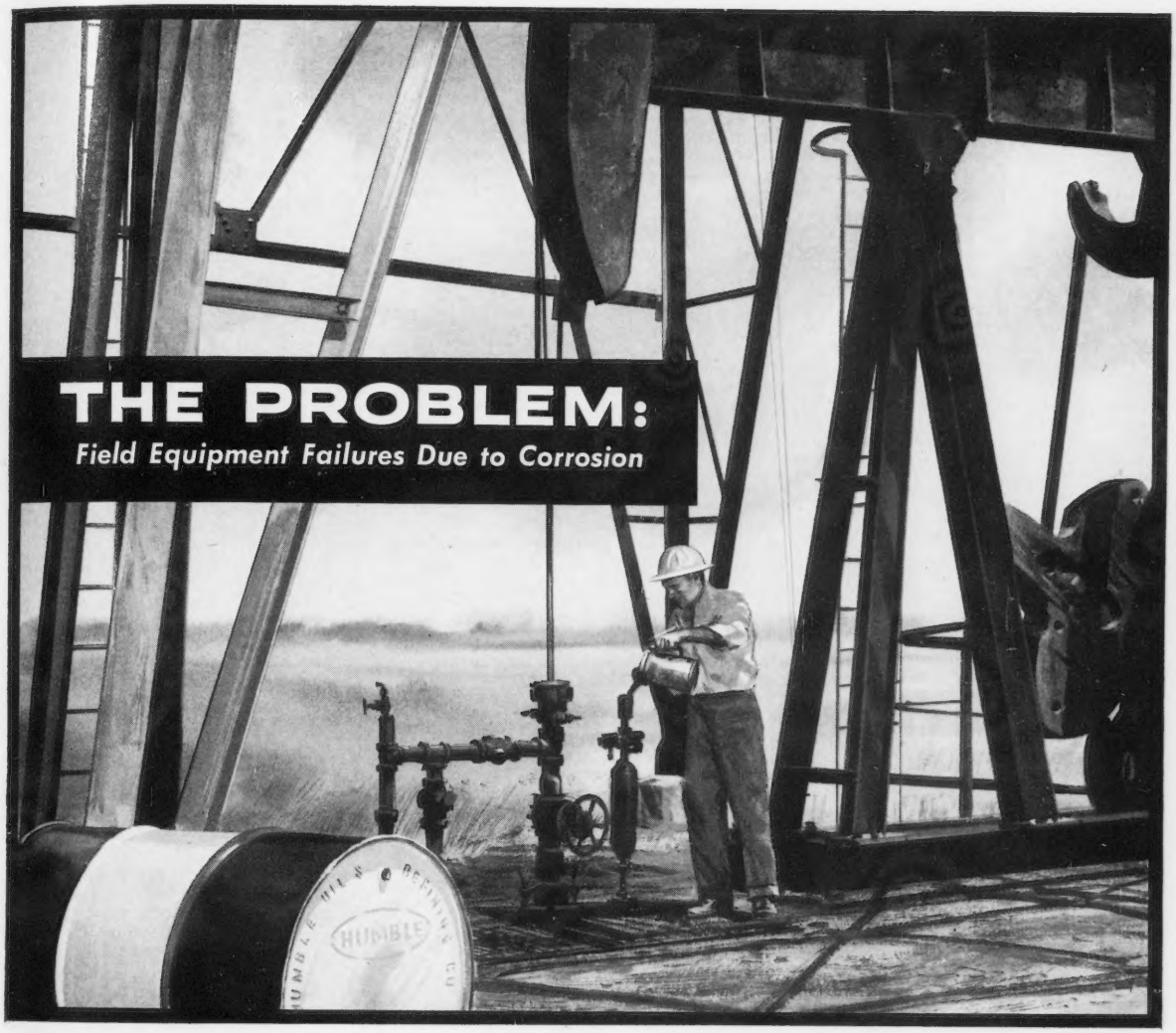


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You will find lifting costs lower when you use *Corexit* because fewer well pulling jobs are necessary, and the life of your equipment is prolonged.

For complete information on *Corexit*, see your nearest Humble wholesale plant in Texas and New Mexico, or write or phone: Technical Service, Sales Department, Humble Oil & Refining Company, P. O. Box 2180, Houston 1, Texas.

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## Program for Houston Jan. 19-20 Pipe Line Short Course Given

Houston Section members attending the Jan. 10 meeting will hear John Watts, Internal Pipe Line Maintenance Co., Odessa, Tex. speak on The Evolution of In-Place Coating Techniques. The section also has planned a two-day Short Course for Pipe Liners to be held Jan. 19-20 in Oberholzer Hall at the University of Houston. The short course will be for field men principally in the pipe line industry and time spent in the course will be equally divided between laboratory and field trips and classroom lectures. Participants are urged to bring corrosion specimens to the short course and to ask questions concerning the corrosion samples and problems they have.

The short course is open to all. Registration fee is $10. It is not necessary to send the money in advance, but those wishing to attend should write in advance to Loyd Nelson, Shell Pipe Line Corp., Box 2648, Houston, Texas so arrangements can be made. A registration desk in Oberholtzer Hall on the University of Houston campus will be open at 7:30 am, Thursday, Jan. 19.

### Lectures Set First Day

The first day's sessions will be held in Oberholtzer Hall and will include discussions on Why Do Pipe Lines Corrode Externally?; External Coating for Pipe Lines; Fundamentals of Cathodic Protection; Why Do Pipe Lines Corrode Internally? and How to Control Internal Corrosion; and Design Construction and Maintenance Planning for the Prevention of Corrosion of Pipe Lines.

### Laboratory Sessions Planned

Friday morning students will be divided into groups. Groups will spend some time in laboratory sessions, and will visit other parts of the campus. In the afternoon, group discussions will be held, the emphasis being on main points of the demonstrations and on individual problems and experiences of the students. This will be followed by a roundtable discussions for the assembled students which will consider problems brought out in group discussions.

At the Dec. 13 meeting of the Section, Edward C. Greco, senior chemist, research department, United Gas Corp., spoke on Relation of the Corrosion Engineer to Management and the NACE to Industry. Mr. Greco pointed out that companies are interested in corrosion engineers who can help them reduce operating expenses, minimize production losses, and who can integrate themselves into the company team. He also told how NACE serves industry through dissemination of technical data and the general advancement of the science. Particularly effective are the NACE technical committees as a means of increasing knowledge of corrosion and of spreading the information learned, Mr. Greco said.

### Past Chairmen Honored

Past chairmen of the section were honored at the meeting by the award of certificates of appreciation. Past chairmen attending were: Walter P. Noser, H. E. Waldrip, Jack L. Battle, Charles Gribble, L. G. Sharpe and J. A. Caldwell. Not present were Oliver Osborn and Perry Spafford. Seventy-eight persons attended the meeting held at John's restaurant.

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## Progress Report on AWS Metallized Steel Test Program Given ISCC

A progress report on the American Welding Society's test program on metallized steel indicates every effort was made to organize the tests so that statistical analyses of results will be significant. The program, designed to test the resistance of zinc and aluminum metallized surfaces to resist atmospheric and sea water corrosion exposures is being conducted by the AWS Committee on Metallizing, Subcommittee III on Corrosion Applications. Sam Tour, of Sam Tour, Inc., New York, is chairman of the Committee on Metallizing.

The program report, dated November 15, explains in detail steps taken to secure test samples of uniform analysis, size, surface and edge finish. Meticulous care was taken to obtain as uniform as possible distribution of the sprayed coatings, and sealing coats of primer, aluminum vinyl and clear vinyl seal coatings. These determinations were made both by area vs weight determinations and by tests with a magnetic thickness gauge.

Uniform distribution of the 4248 panels included on the test among the seven test sites maintained by the American Society for Testing Materials Advisory Committee on Corrosion was assured by a careful statistical selection. Test sites include three marine sites and three inland industrial sites.

Careful plans were made for the identification of panels, selection of panels from among those tested, recording of results and criteria for visual evaluation of results. Evaluation of the coatings at intervals of 1, 3, 6 and 12 years are contemplated. The panels will be examined yearly to determine the life of the coatings before failure, so that more exact failure data will be available than could be obtained by examination at the projected intervals.

First examination of exposed panels already has been made. The report says that except for discoloration of coatings, no serious corrosion attack seems to have taken place on any of the coatings at any location. Specimens have been returned to the central location where they are to be kept for comparison with specimens removed from each test site in the future.

The program, initiated in July 1950 is estimated by the chairman, Mr. Tour, to be in the $100,000 class.

(The report was made to the NACE Inter Society Corrosion Committee by Mr. Tour on behalf of the sponsoring organizations.)

## Eleven Correspondents Report to ISCC on Foreign Corrosion Work

Reports have been received from eleven correspondents on corrosion of the Inter Society Corrosion Committee, a group sponsored by the National Association of Corrosion Engineers. The committee is intended to provide mutual exchange of information concerning corrosion mitigation studies in progress or planned.

Organizations of corrosion engineers are being formed in Germany, Italy and Switzerland in addition to those which have been reported formerly. Numerous regional meetings were reported.

### Austria

Franz Ritter—Corrosion Association of Austria has been organized. The Association of Austrian Chemists held a symposium on High Temperature Materials on September 23-25, 1954, where corrosion topics were handled.

### Denmark

E. Knuth-Winterfeldt—The Danish Corrosion Committee serves as connecting link between corrosion laboratories and technical corrosion committees sponsored by Danish Academy of Technical Sciences. The Tube Corrosion Committee studies pitting corrosion of galvanized tubes in domestic hot and cold water. The Boiler Corrosion Committee studies the deterioration of steel tubes in oil-fired boilers. A review and literature survey has been prepared on cathodic protection.

A Scandinavian Corrosion Symposium was held in Copenhagen on May 6-8, 1954. A cooperative testing program to develop accelerated tests for paints is being developed.

### France

G. Chaudron—An international con-

(Continued on Page 106)

## New Orleans-Baton Rouge Section Weighs Student Corrosion Interest Contest

A contest, with a prize to be offered in the field of corrosion by the New Orleans-Baton Rouge Section has been proposed at a meeting of the section. Frank S. Bird, The California Co., discussing the lack of interest of high school students in science and technical work, suggested a contest consisting of exhibits and displays with local winners going to a state contest and the state winners to a national contest. A further study of his proposal will be made.

The November 1 meeting of the section at Phil's Place in Harvey, La., was attended by 12 members and 12 guests. The business session opened with a report by William J. Eads, Products Research Service and a letter from Joy T. Payton of Houston Section concerning a proposed painting society to be made up of coatings applicators, suppliers and users. Action on the proposal was delayed.

Clifford L. Barr, Shell Oil Co., Donaldsonville, La., was elected vice-chairman unanimously, succeeding Lee N. Spinks, Cathodic Protection Service, who became chairman upon the resignation of J. R. Matherne, transferred.

Floyd Thorn, senior corrosion engineer, Cathodic Protection Service, Houston spoke on "Corrosion Control in Production Equipment." He covered gathering lines, production vessels and casing.

Al Smiles, Factories Manager of International Paint Co. was the scheduled speaker for the December 1 meeting on "Selection and Application of Marine Paints and Coatings."

## Five Meetings Planned by New Orleans-Baton Rouge Section During 1956

Five meetings have been scheduled by New Orleans-Baton Rouge Section in 1956. This is in addition to sessions held in September, October and November, 1955. Meetings have been scheduled as follows:

January, date and place to be set. Sweet Oil Well Corrosion, H. E. Greenwell, The Atlantic Refining Co., Dallas.

February, date and place to be set. Corrosion Metallurgy of High Strength Tubing and Casing, F. J. Radd, Continental Oil Co., Ponca City, Okla.

March, date and place to be set. Maintenance Painting, Paul Weaver, Sement-Solvay Division, Allied Chemical and Dye Corp., Baton Rouge, La.

April, date and place to be set. Panel Discussion: Corrosion Problems in Utilities Companies. Moderator, C. L. Barr, Shell Oil Co., Donaldsonville, La. Panel: R. J. Dowe, Southern Bell Telephone and Telegraph Co., New Orleans; S. E. Trouard, New Orleans Public Service, Inc.; A. W. Durning, New Orleans Public Service, Inc.; Herbert Swan, Sewerage and Water Board, New Orleans (unconfirmed).

May, date and place to be set. Corrosion Control in Offshore Operations, F. S. Bird, California Company, New Orleans.

No meetings are scheduled for June, July and August.

•

Reprints of technical committee reports of NACE usually are available.

## Marine Paints, Coatings Are Surveyed at New Orleans

Selection and Application of Marine Paints and Coatings was discussed at the December 1 meeting of New Orleans-Baton Rouge Section. Present at the Engineers and Architects Club of New Orleans were 21 members and 28 guests. C. L. Barr, Shell Oil Co., presided in the absence of the chairman. Mr. R. M. Robinson, treasurer, urged guests to consider the advantages of becoming members of NACE.

Al Smiles, International Paint Company, Inc., New York, the technical speaker reviewed recent important developments in the paint industry, especially synthetic materials which increase control of raw material quality and properties of the finished products. Surface preparation was stressed as a prerequisite to engineered coatings by Mr. Smiles.

Selection of primer and finish coats was considered, together with the special problems encountered in protecting surfaces of floating equipment. Factors to be considered in selecting and applying paint systems were listed by Mr. Smiles as: Pretreatment of surface, primers with sufficient inhibitive pigment, multiple coats, adequate dry film thickness and an effective maintenance program.

H. E. Greenwell, Atlantic Refining Co., Dallas, is scheduled to address the January meeting at a date to be set on "Sweet Oil Well Corrosion."


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## Eleven Correspondents—

(Continued From Page 104)

gress on aluminum was held in Paris in June, 1954. The two French magazines dealing with corrosion, Corrosion et Anti-Corrosion and Metaux, Corrosion-Industries, are focusing attention on both theoretical and practical phases of corrosion.

### Germany

G. Schikorr—The Industrial Corrosion Association of Technical-Scientific Societies was reactivated in 1954 and held a two-day meeting. The Committee on Magazine Packing, with the help of the Foreign Operations Administration, Washington, D. C., and the Rationalization Board of the German Administration, Frankfurt/M, conducted a tour of the U. S. to study warehouse packaging. A Committee on Seaworthy Packaging has been organized.

Corrosion committees of five technical societies held annual meetings.

A number of committees are actively engaged in preparing general directives and standards: German Steel Construction Society—Corrosion protection in steel construction; German Society of Gas and Water Specialists and Association of German Electrical Engineers—Protection of cables and pipe lines; Standardization Committee on Testing Materials—Units of measuring corrosion, oil testing and protection by metallic and non-metallic coatings; Association of German Chemists—Evaluation of cold and hot waters on corrosive behavior; German Iron Workers Society—Coating of steel structures in foundries, testing and use of stainless and heat resistant steels; and Central Society of Electrical Industries—Iron and aluminum for cable casings.

### Holland

C. A. Lobry De Bruyn—The Corrosion Discussion Group made up of a limited number of members treated a variety of subjects, including influence of electron structure of a metal on the velocity of electrochemical reactions, inhibitors, corrosion of stainless steel, undercutting of paint films, etc. In addition, short courses on corrosion were given in the main industrial centers of Holland.

Special corrosion committees are active. The Soil Corrosion Committee reported results of fifth inspection of soil exposure tests on unprotected cast iron and steel pipes. Reports on measurement of electrical conductivity of soils and on cathodic protection in a specially aggressive environment are ready for publication.

### Japan

T. Fujiwara—The six active corrosion committees are: Corrosion Committee of the Japan Society for Promotion of Science; The Technical Committee for Prevention of Corrosion, affiliated with the Japan Electrochemical Society; Electrical Corrosion Research Committee, affiliated with the Institute of Electrical Engineers of Japan; and Electric Corrosion Control Committees of Tokyo, Kansai and Tokai.

### Italy

R. Piontelli—Fundamental research has concerned electrochemical behavior of metals with emphasis on new techniques for measuring overvoltages and effect of diffusion on corrosion in aerated solutions.

The papers and discussions presented at the Corrosion Meeting in Milan in 1953 were published as a supplement to *Metallurgia Italiana*. A symposium on tin coatings was held in September and the papers will be published as a supplement to the above journal.

A National Society of Corrosion Engineers is in process of formation. A review on the popular problems in corrosion is being published in Rome.

### New Zealand

F. J. T. Grigg—No committee activities. The Department of Scientific and Industrial Research continued studies of corrosion by geothermal steam, industrial water and soil; protective systems for aircraft, hydro-electric plants and idle ships (cathodic protection); and corrosion of aluminum roofing.

### Norway

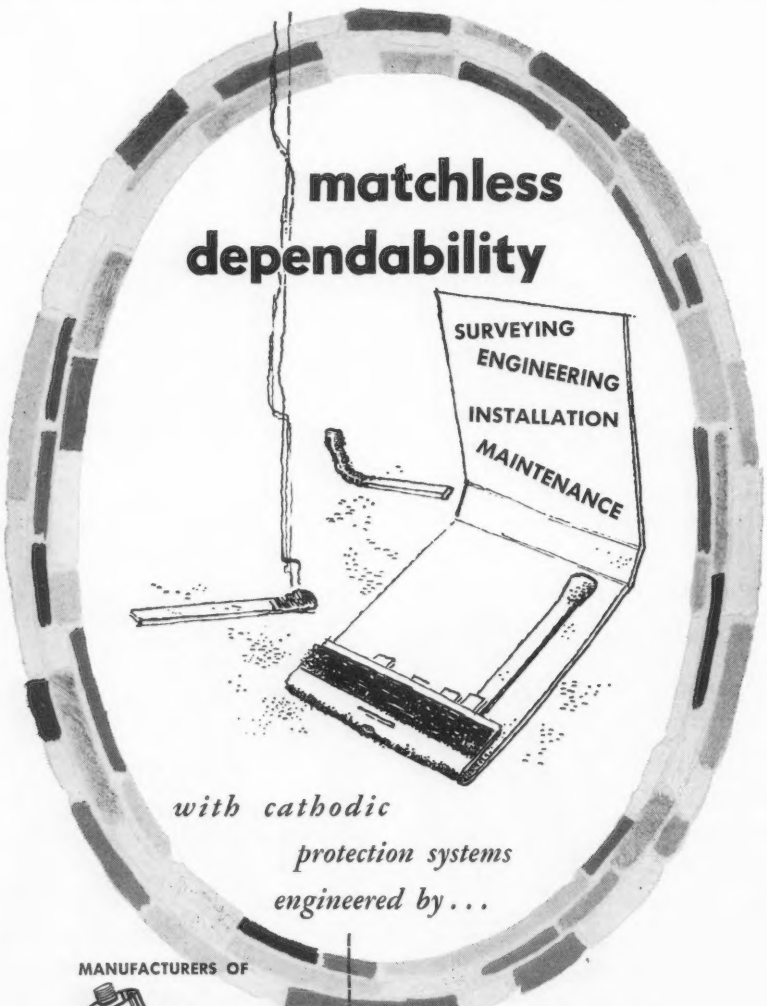
A. B. Winterbottom—A conference titled "Against Rust and Rot" on June 16-17, 1954, was the high light of the year. A Nordic Corrosion Congress was held in May in Copenhagen. Studies on atmospheric corrosion and tank ship problems are progressing.

### Spain

E. Jimeno—Intensification of industrialization is focusing attention on corrosion. Special consideration is being given to soil corrosion and to boiler corrosion.

### Switzerland

E. Brandenberger—Six papers on a variety of corrosion topics were published. On January 29, 1954, the Swiss Association of Engineers and Architects formed a corrosion committee to standardize the protection of all kinds of structures against corrosion.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# GENERAL NEWS

## Corrosion Course to Be Held at Monterrey, Mexico

A Corrosion Short Course will be held February 1-3 inclusive at Monterrey, Nuevo Leon, Mexico under auspices of Instituto Tecnologico y de Estudios Superiores de Monterrey. Ing. Carlos, Duhne, Head, Chemical Engineering Department, is in charge.

A tentative program has been announced as follows:

**Wednesday, February 1**

Corrosion and cathodic protection simplified.
Round table discussion of practical installations.
Protective coatings.
Insulated couplings and plastic tapes, their use and abuse.
Round table discussions.
Motion picture.

**Thursday, February 2**

Corrosion control instruments.
Galvanic anodes.
Protecting multiple pipe lines.
Plant protection problems.

**Friday, February 3**

Protecting a city's gas distribution system.
Gas distribution corrosion problems in Monterrey, Mexico.
Communications and corrosion.
Brief history of protective pipe line coatings in the United States.
Protective coatings in Mexico.
Round table discussions.

## Truck Exhaust Afterburner Cuts Smog Hydrocarbons More Than 95 Percent

The Clayton Afterburner, a device developed in Los Angeles has eliminated more than 95 percent of the smog-forming hydrocarbons from automotive exhaust gas in tests. This was reported by the Air Pollution Control District of Los Angeles. The device, in experimental use on 10 busses of the Los Angeles County system and one private transportation company, has proved successful.

Intended for use only on large gasoline-powered vehicles, it costs $100 to $200 per vehicle, has a life expectancy greater than that of standard mufflers and requires checking every 20,000 miles. Development work is under way for devices applicable to Diesel engines and passenger cars.

The stream of exhaust gas from the engine sucks in sufficient air to cause combustion of the unburned or partially burned fuel carried into the exhaust system. Exhaust gases are ignited by a spark plug in the muffler while baffles prevent flame emission from tail pipe.

In use the device reduces hydrocarbons 97 percent, aldehydes 39 percent, acetylene 69 percent and carbon monoxide 81 percent in over-all operation. Aldehydes are credited generally as being the source of lachrymers.

## New Concepts on Underground Cathodic Protection of Power Cables Advanced

Methods developed to protect the underground power cable system of Florida Power and Light Co., Miami have been described by J. B. Prime, Jr., in his paper "Application of Cathodic Protection to Underground Cable Systems." Mr. Prime presented his paper September 29, 1955 before a meeting of the Transmission and Distribution Committee of the Edison Electric Institute in New Orleans.

New concepts for underground protection described by Mr. Prime included:

1. Use of a jacketed neutral on top of all new duct line extensions.

2. A new type grounding system for manholes (Figure 1), which has facilities for isolating cables from system neutral and for cathodic protection of cables by a buried zinc anode. At the end of the 10-year design life of these anodes the company plans to apply forced drainage to the outer perimeter of radial cables.

3. On metallic sheathed submarine cables a grounding system is used (Figure 2) isolated from the system neutral and grounded with a galvanized rod at each terminal pole of 25 ohm resistance or less.

4. Four 60-lb. magnesium anodes per 4000-foot 3-conductor submarine cable are expected to protect it for nearly four years. Cable structure negative is shifted 0.3 to 0.5 volt, considered adequate.

5. Non-metallic submarine cable with armor has shielding tape bonded to the armor and both are protected with magnesium anodes.

6. Transmission cables are protected in a similar way. About 15 miles of 69 KV pipe-type cable is protected by a coating, isolated, and given a 2.2 volt potential between pipe and neutral ground by station batteries. A path for fault current is provided through batteries. (Figure 3.)

Mr. Prime points out that initial potential surveys were conducted cooperatively with Southern Bell Telephone and Telegraph Company and others.

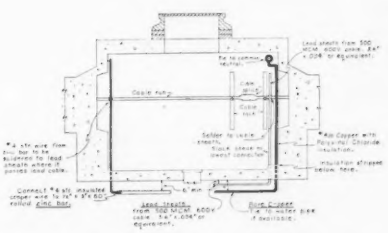

Figure 1—Special manhole and grounding scheme.

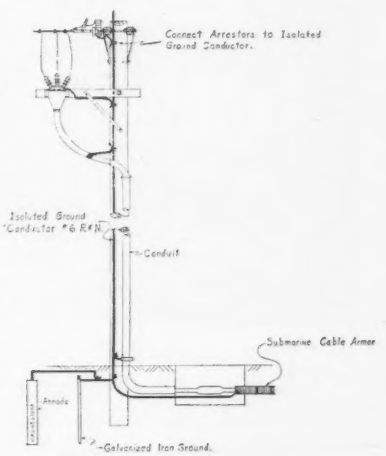


Figure 2—Grounding of submarine cables.

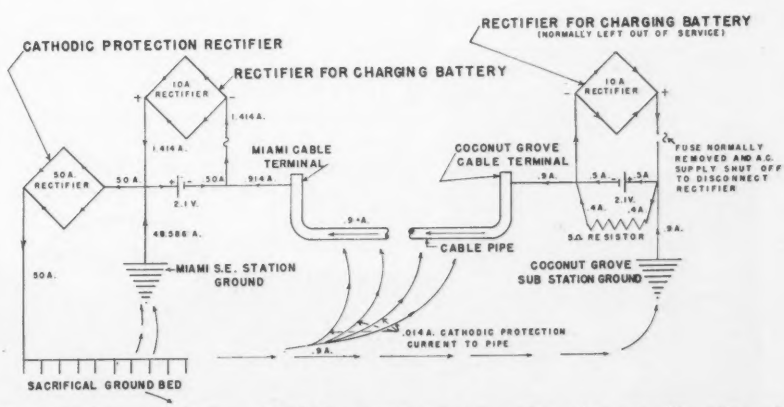


Figure 3—Schematic diagram of cathodic protection and grounding scheme for Miami-Coconut Grove 69 KV cable pipe.

## European Federation of Corrosion Details Given

Details of the European Federation of Corrosion, an organization of 40 technical societies in Europe, recently have been revealed by Dr. Bretschneider, head of the Frankfurt am Main secretariat of the organization. The federation is designed to accomplish many of the same purposes for which the National Association of Corrosion Engineers was formed and for which the Inter Society Corrosion Committee was organized. Organization was reported in Corrosion's August, 1955 issue.

Rules and regulations of the federation describe the organization as being composed of representatives of the subscribing technical organizations, without dues and governed by an elective board of directors and executive committee. The aim of the federation is to further Euorpean cooperation in corrosion research, corrosion mitigation methods and materials protection.

Secretariats are being maintained at Dechema headquarters in Frankfurt and at Societe de Chimie Industrielle in Paris. European conventions for technical discussions, working parties on specific problems, exchange of information and cooperation with foreign organizations are contemplated.

The number of societies in the participating countries is: Germany, 8; France, 11; Greece, 1; Italy, 2; Jugoslavia, 2; Luxembourg, 1; Austria, 5; Portugal, 1; Spain, 2; Sweden, 1; Switzerland, 4; Finnland, 1; Norway, 1.


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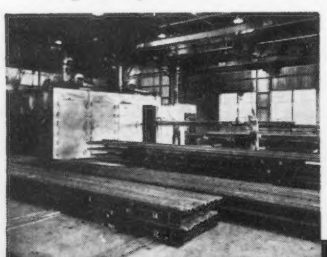

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## BOOK REVIEWS

**Recommended Practices for Metallizing: Part ID—Metallizing Flat Surfaces.** (Tentative). 16 pages, 6 x 9 inches, paper cover. 1955. The American Welding Society, 33 West 39th St., New York 18, N. Y. Per copy, 50¢. This is the fourth in a series of AWS reports on metallizing. Included are surface preparation, covering cleaning, undercut, bonding coatings, grooving, groove and rotary roughing tool method, groove and knurling method and studding. Spraying equipment and materials are detailed with formulae and tables for weight, spraying procedure, causes and prevention of cracking, physical properties of sprayed metals and finishing.

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**The Welding of Austenitic Chromium-Nickel Steel Piping and Tubing.** 32 pages, 6 x 9 inches, paper cover. 1955. American Welding Society, 33 West 39th St., New York 18, N. Y. Per Copy, $1.

A committee report intended as a guide to prevent difficulties in welding austenitic stainless steel. While written specifically for piping and tubing, many of the recommendations are equally applicable to other forms of stainless steels.

A section devoted to the corrosion resistance of welds includes information on intergranular corrosion, stress corrosion cracking, crater corrosion, galvanic corrosion. Consideration is given also to sigma phase formation, suitability of various grades for welding and recommended rods for various grades.

## Phenol Emission from Burning Trash Measured

For every ton of rubbish burned in backyard burners about eight pounds of phenols are emitted, according to studies made by Battelle Memorial Institute, Columbus for the Air Pollution Foundation. Aldehydes, such as formaldehyde appeared in concentrations from 5 to 64 pounds per ton of rubbish burned.

While this contaminant is not considered a smog causing material it is believed injurious to health.

Because of the inefficiency of backyard burners hydrocarbons appeared in a range of 44 to 293 pounds per ton in aerometric surveys; methanol was measured in amounts from 9 to 23 pounds per ton and various other pollutants, excluding carbon monoxide ranged from 32 to 407 pounds per ton. Carbon monoxide, not considered a smog-forming gas was present in the range of 197 to 990 pounds.

Refuse burned included paper, cardboard, grass and hedge clippings.

## Use of Atomic Energy in Chemical Reactions Studied

Use of atomic energy to cause chemical reactions will be explored under a research grant given the Stevens Institute of Technology by the U. S. Atomic Energy Commission. Radioactive cobalt will be used as the energy source to develop information on the effect of these high energy gamma rays on materials.

One outcome of the research may be the use of atomic energy to trigger reactions instead of heat.

## Corrosion Discussions Set at Maintenance Conference

Among the discussions scheduled during the 7th Plant Maintenance and Engineering Conference January 23-25 at Convention Hall, Philadelphia are:

Maintenance Painting, a panel discussion. Capt. E. J. Peltier, Assistant Chief for Maintenance Materiel, Bureau of Yards and Docks, Department of the Navy, Washington, chairman.

Maintenance Problems in Chemical Plants, W. E. Chandler, Plant Engineer, John F. Queeny Plant, Organic Chemical Division, Monsanto Chemical Co., St. Louis, discussion leader.

Maintenance Problems in Petroleum Refining Plants, W. H. Fletcher, Superintendent of Maintenance, and Construction, Standard Oil Co., Cleveland, discussion leader.

Maintenance Problems in Paper Mills and Paper Product Plants, Thomas Foulkes, Chief Plant Engineer, E. B. Eddy Co., Hull, Quebec, discussion leader.

## Wood Deterioration Probed By Building Advisory Board

"Protection Against Decay and Termites in Wood Frame Construction" is being studied by a committee of the Building Research Advisory Board. The committee consists of 14 experts in entomology, plant pathology, toxicology, wood technology and moisture and vapor control.

Another committee is studying standards for domestic hot water heating equipment. A principal interest is to establish standards to insure long life (8-10 year's service is considered satisfactory).

## British Industries Fairs Set for February and April

A list of industries eligible for participation in two British Industries Fairs has been announced in London. Consumer goods will be featured in the Feb. 22-Mar. 2 Fair and technical and heavy industries will be shown at the April 23-May 4 Fair. Further information may be had from British Information Services, 30 Rockefeller Plaza, New York 20, N. Y.

## Junior AIChE Award Given

William E. Ranz, Associate Professor in Engineering Research, Pennsylvania State University, University Park, Pa. has been given the 1955 Junior Award of the American Institute of Chemical Engineers in chemical engineering. Outstanding contributions to the literature of chemical engineering are the basis for the award.

## E. F. Lundeen Is Honored

E. F. Lundeen, assistant superintendent of quality control, Inland Steel Company, Chicago received the 1955 Annual Award of the Galvanizers Committee of the American Zinc Institute, Inc. A gold watch was given to Mr. Lundeen during the institute's Chicago meeting.


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TAPECOAT-X is designed for today's needs in protecting pipe, pipe joints, fittings, mechanical couplings, tanks, and other surfaces vulnerable to corrosion . . . above or below ground. Available in rolls of 2″, 3″, 4″, and 6″ widths.

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The extra thickness of coal tar in TAPECOAT-X permits a single-wrap application to make it go farther, faster and reduce labor costs.

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With reduced labor cost, greater coverage and faster application. TAPECOAT-X saves you money right down the line.

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## Equipment Services NEW PRODUCTS Materials Literature

**Hydrogen Peroxide** concentrations between 90 and 100 percent pure are being made commercially by Becco Chemical Division, Food Machinery and Chemical Corp., Buffalo, N. Y. Continuous fractional crystallization is used.

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**Inorganic and Organic Tin Chemicals,** organotin stabilizers, stannous soaps, antimony chemicals, zirconium products and various metals and alloys produced by Metal and Thermit Corp. are described in a bulletin titled "M & T Chemicals and Other Products," available from the company at 100 East 42nd St., New York 17, N. Y.

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**Nubelite,** a custom-formulated industrial paint for metallic surfaces is described in a brochure available from The Glidden Company's Paint Division, 11001 Madison Ave., Cleveland 2, Ohio. High humidity resistance and superior film strength are among the qualities claimed.

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**WW Alloys, Inc.,** a division of Fansteel Metallurgical Corp., 11644 Cloverdale Ave., Detroit 4, Mich. has issued a 32-page booklet, Technical Data Bulletin 15.100-1. Data are given on the firm's premium quality aluminum bronzes, including physical properties, applications, nominal chemical composition, available forms and machining recommendations.

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**Hagan Water Softeners** for industrial and institutional use are described and illustrated in a bulletin available from Hagan Corp., 323 Fourth Ave., Pittsburgh 30, Pa. Capacities range from 20 to 175 gallons per minute.

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**Ni-Vee Bronzes,** special nickel-tin bronzes developed by The International Nickel Co., Inc., 67 Wall St., New York 5, N. Y. are thoroughly described in a 28-page and cover booklet issued by the company. The Ni-Vee bronzes are suggested as a means of consolidating brass and bronze compositions into basically five simple compositions, providing for interchangeability among the compositions and improvement in cast properties by simple heat treatment. In addition to the usual narrative and tabular data, photographs showing uses, graphs illustrating some properties and microphotographs of some types are given. Considered also is corrosion resistance, service at elevated temperatures and non-magnetic and electrical properties.

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**1956 Guide to Improved Packaging,** a bulletin describing Bakelite Plastics and Resins applied to packaging problems is available from the Bakelite Company, a Division of Union Carbide and Carbon Corp., 300 Madison Ave., New York 17, N. Y. Included are data on vinyl resins, phenolics, styrene, rigid vinyl and polyethylene. Information is given on vinyl adhesives.

•

**Kemp Dryers,** Bulletin No. D-100, is available from C. M. Kemp Manufacturing Co., 405 East Oliver St., Baltimore 2, Md. The Kemp dryer is an enclosed desiccant bed of absorbent material designed to extract moisture from air, gases and liquids continuously. Capacities range from one to 30,000 cfm and design pressures from atmospheric to 6000 psig. Reactivation is by heating. Desiccants used are related to the service required. The bulletin gives flow diagrams and describes design features and tabulates dimensional data and utilities required.

•

**Epon 815,** a low viscosity structural resin is the latest addition to Shell Chemical Company's line of resins. The new resin is recommended for use in laminates prepared by the vacuum bag and pressure techniques. Contact pressure laminates with glass contents as high as 60 percent and vacuum bag laminates with contents in the range of 70 percent are possible.

•

**Polyethylene** water tanks with a capacity of 1028 gallons each were con-

(Continued on Page 111)

Announcing the improved
TYPE "Z"
WmSEAL CASING
BUSHING
STAINLESS STEEL CLAMPS ARE HAND TIGHTENED, NO TOOLS REQUIRED
SOLID RING OF TOUGH SYNTHETIC RUBBER — NO JOINT
TIGHTER SEAL WITH WIDE STAINLESS STEEL BANDS AND CLAMPS
"Z" BUSHINGS STAY PUT EVEN IF PIPE MOVES IN CASING
COMPLETE CORROSION RESISTANCE
NO SHIELD REQUIRED
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## NEW PRODUCTS

(Continued From Page 110)

structed for the USSS Cormorant, a Navy minesweeper by American Agile Corp., 5461 Dunham Road, Maple Heights, Ohio. The all-welded tanks each weighed 675 pounds versus similar tanks of Monel weighing 5737 pounds. The polyethylene tanks were used because the minesweeper must be non-magnetic.

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**JaLizing,** a 5-stage phosphatizing system was incorporated in the new Jones & Laughlin Steel Corporation Container Division plant at Port Arthur, Texas.

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**Nu-Dri,** a proprietary compound made by St. Helen Products Co., St. Helen Michigan and distributed by Gettel Products Co., 1313 East 29th St., Houston 9, Texas can be brushed, sprayed or rolled like other paints. It dries into a flexible water-proof coating, manufacturers say, on metal or non-metallic surfaces, being useful even as a waterproofing compound for tarpaulins. The material may be applied also to such surfaces as automobile mufflers, to which it adheres tightly and seals small cavities. It is available in aluminum, buff, green, blue-gray, rust red and black.

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**A Surface Skimmer** added to its solids-contact clarifier makes it possible for Graver Water Conditioning Co., 216 West 14th St., New York, N. Y. to offer a method of clarifying water containing both settleable and non-settleable particles. It is most effective in treating waters from pulp and paper mills and removing oil from water which also contains settleable particles.

•

**Sodium Hypophosphite,** a chemical required in the non-electrical nickel plating of iron is being produced in a new plant built by Victor Chemical Works, Nashville, Tenn. The material, a phosphorus-based chemical has been used previously only in so-called patent medicine tonics.

•

**PVC Pipe Fittings and Flanges,** a 12-page brochure available from Tube Turns Plastics, Inc., 2929 Magazine St., Louisville 1, Ky. illustrates and describes the polyvinyl chloride fittings and flanges available from the company. Advantages of PVC over other materials are listed and some indications are given of the probable increased need for corrosion-resistant piping in the chemical field and others. Tables with dimensions, weights and other characteristics are provided.

•

**Cathodic Protection Systems for Corrosion Control,** a brochure available from The Harco Corp., 16991 Broadway, Cleveland, Ohio describes the practical and economical advantages of using cathodic protection on buried or submerged metals. Services available from Harco are listed.

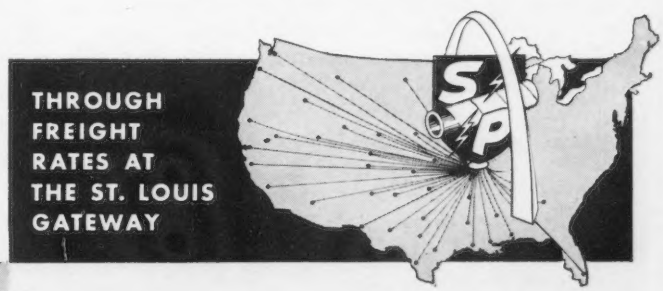
•

**Bakelite Compounds for Monofilament Extrusion** are described and illustrated in the November, 1955, No. 2 issue of Bakelite Extruderitems. Data are included on styrene and styrene-acrylonitrile copolymers, polyethylene and vinyls.

(Continued on Page 112)

In 1955, C/W pipe sales again increased over the previous year. This is the sixth straight year that SPI's sales have shown a substantial increase.

Here again is proof of the industry's acceptance of the fact that SPI has all the machines, methods, and procedures necessary to produce the finest coated and wrapped pipe, and that SPI personnel has constantly made certain that your pipe has been delivered in time to meet your schedules.

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# NEW PRODUCTS

(Continued From Page 111)

**Brazing** under high vacuum is being investigated as a metal joining method by Pratt & Whitney Aircraft division of United Aircraft Corp. Because the brazing is done in an atmosphere free of oxidizing gases, improved performance is expected from the joints. NACA Technical Note No. 3450 reveals joints with shear strengths on the order of 63,000 psi have been obtained under vacuum brazing conditions versus 42,000 psi shear strengths in dry hydrogen. Pratt and Whitney tests show copper brazed joints in stainless steel and nickel alloy test pieces did not have quantitatively improved shear strengths over joints brazed in hydrogen and dissociated ammonia. Peel tests showed vacuum brazed joints more ductile.

•

**Cath-O-Chem** is the name of a new system for protecting the submerged surfaces of fire protection tannks. Developed by Electro Rust-Proofing Corp. (N. J.), 25 Main Street, Belleville 9, N. J., the system calls for addition of non-oxidizing salts or colloidal substances to the water, combined with cathodic protection. Reduced installation and operating expense of cathodic protection is claimed, as well as better distribution of current to submerged surfaces. The system is described in publication TP-111-E available on request.

•

**Stainless Fasteners,** a stock list and data book on the products of Allmetal Screw Products Co., Inc., 821 Stewart Ave., Garden City, N. Y. is available on request. First part of the 52-page 2-color book illustrates and gives dimensions of forty basic fastening devices. The second part gives engineering data on materials.

•

**Precision Metals Service,** a 16-page folder, describes the production of metals of special alloys, precision rolled strip and drawn wire in limited quantities. The Allied Products Div., Hamilton Watch Co., Lancaster, Pa. has copies of the bulletin available. The plant produces 10-lb. ingots to specification.

•

**113-Line Fast Drying Finishes** can be handled in about 15 minutes after application. The synthetic pigmented enamels are designed for application to heavy equipment. Good adhesion directly to solvent cleaned metal is claimed by DuPont Company Finishes Division, Wilmington, Del.

•

**This is Inco's Huntington Works,** a 40-page and cover booklet describes the wide variety of operations at this plant. Refining, milling, forging, rolling, annealing, extruding, cold drawing and custom services are described and illustrated.

•

**Graphite** anodes, Type QA are attached by means of crimp type connectors to size 4, 6 or 8, seven-strand cable, at any desired spacing. They are shipped ready for assembly in 2 x 12, 2 x 20 and 3 x 30-inch sizes. The anodes are intended for installation in cable ducts where cathodic protection is being applied by impressed current. They can be installed also parallel to buried piping. When installed in carbonaceous backfill the new anodes show costs comparable to larger anodes while being more flexible and with generally lower circuit resistance per ampere capacity. They are fully described in Bulletin S-6525 available from National Carbon Co., Division Union Carbide and Carbon Corp., 30 East 42nd St., New York 17, N. Y.

•

**United States Steel Corp.,** has developed a new grade of stainless steel containing little or no nickel. The steel was described in a paper by Dennis J. Carney, of United States Steel Corp., read before the Cleveland regional technical meeting of the American Iron and Steel Institute, Oct. 11. Mr. Carney states that proper adjustment of the chemical composition of the steels, particularly with regard to the chromium and manganese contents make it possible to produce sound ingots with a nitrogen content of more than double the old limit.

•

**Kaiser Aluminum & Chemical Corp.,** Kaiser Bldg., 1924 Broadway, Oakland 12, Cal. is now marketing a special high purity grade ingot of 355 and 356 aluminum alloys. By reducing impurities to much lower levels, permanent mold castings are given a higher reserve of ductility. They can therefore be subjected to more complete artificial aging in heat treatment to develop full strength potential and still retain greater elongation, the firm explains.


PROTECT OIL AND GAS PIPE LINES with
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★ Nicolet "Tufbestos" 8 lb. *Asbestos* Felt reinforced with Parallel glass yarns, Tar or Asphalt Saturated
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*Asbestos* is *inorganic.* We believe this *inorganic* material, which comprises the major contents of the base felt, provides a longer-lasting shield protection for all pipe line enamel coatings.

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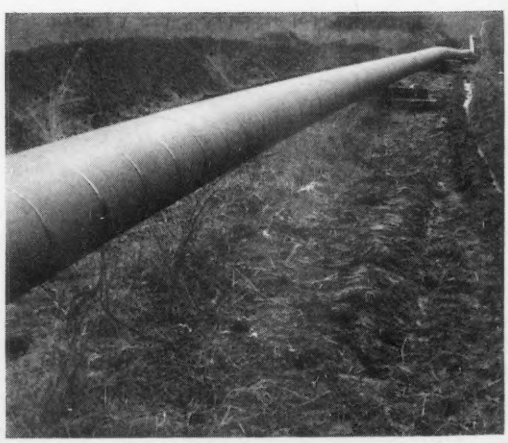

Photo showing Nicolet Felt Protecting Pipe Line

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## ST. JOE *electrothermic* ZINC...

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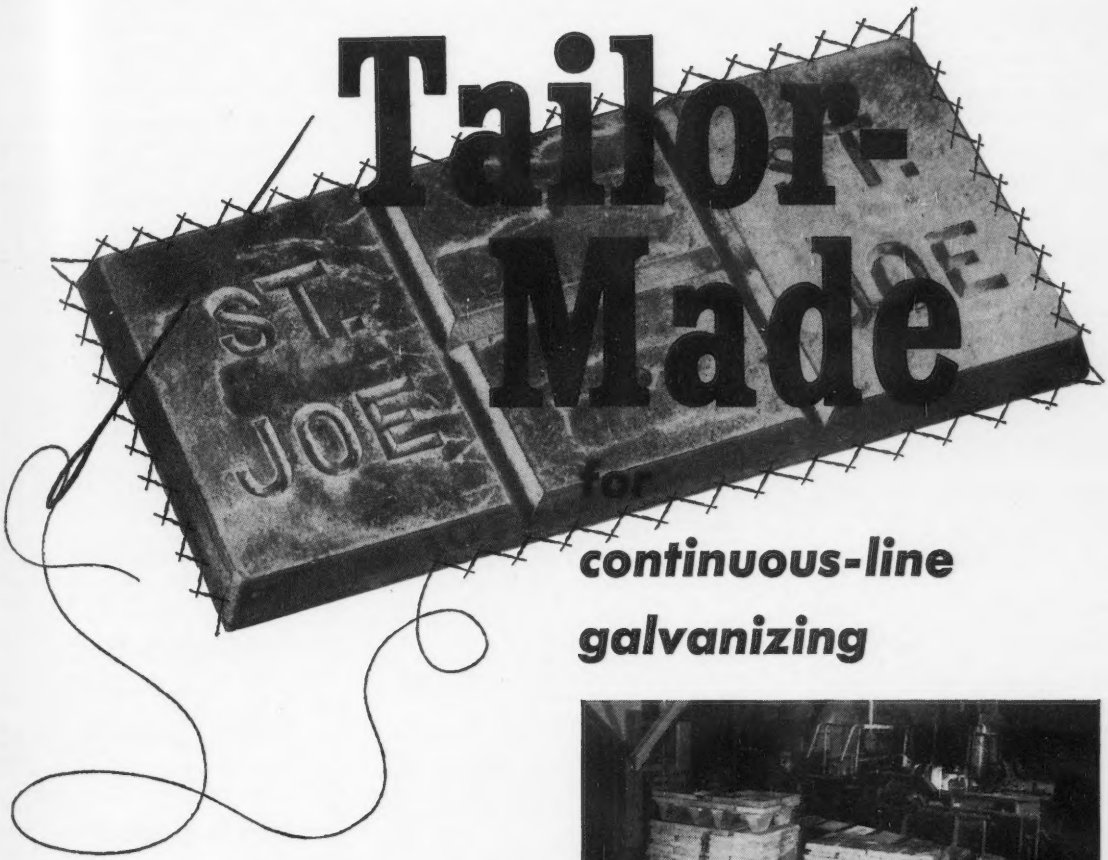

Zinc slabs being fed by conveyor into the melting pot of a continuous galvanizing line.

AS MORE AND MORE lines come into production, it becomes increasingly evident that the compositions of the various zincs required for continuous galvanizing are more exacting than those established by A.S.T.M. specifications. In fact, the grades are almost as numerous as the lines in operation, since each company's metallurgists feel that the composition of the metal they specify is best suited for their particular product. Depending on operating variables, a line might require a controlled lead content with low cadmium either with or without the addition of aluminum by the smelter. Another line might specify a different lead content and a fixed amount of aluminum with rigid limits on other ingredients.

St. Joe's patented electrothermic smelting process, coupled with a highly flexible roasting, sintering and blending operation, permits a degree of control in the metal's composition which cannot readily be achieved by any other method. As a result, the St. Joseph Lead Company is in the unique position of being able to supply zinc to virtually any specification which operators of continuous galvanizing lines consider most desirable for their individual requirements.

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250 PARK AVENUE, NEW YORK 17, N. Y.

HIGH GRADE
INTERMEDIATE
PRIME WESTERN
**ST. JOE *electrothermic* ZINC**

# MEN in the NEWS

**C. L. Peterson** has been appointed vice president and general manager of the Brown Instruments Division, Minneapolis-Honeywell Regulator Co., New York, N. Y. Peterson had formerly been divisional vice president.

•

**George F. Sharrard** recently was promoted to director of research and development of R. M. Hollingshead Corp., Camden, N. J. He previously was manager of the technical service division and formerly was associated with Chas. Pfizer & Co.

•

**F. P. Spruance, Jr.** recently was named vice-president of the American Chemical Paint Co. and sales manager of the metalworking chemicals division. He will direct the sales program of the Ambler, Pa. firm's metalworking chemicals division. He succeeds **F. P. Spruance, Sr.** who, although he resigned one position, continues as a director of the company.

•

**Edmond S. Bauer** has been named assistant director of sales for resin products and **Thomas W. Sears** sales manager for industrial resins by Monsanto Chemical Company's Plastics Division.

•

**Gilbert H. Spector** has been appointed director of sales promotion and merchandising for Gates Engineering Co.

•

**Frank C. Amsbary, Jr.,** president of the American Water Works Association has been made vice-president and general manager of the Long Island Water Corporation, which serves 19 South Shore communities centering around Lynbrook.

•

**Edward P. Sandowsky** has joined the Development and Research Division of The International Nickel Co., Inc. as research metallurgist in the Iron Alloys Section of the Research Laboratory at Bayonne, N. J.

•

**James C. Bell** is a new member of the engineering Staff of Corrosion Services, Inc., Tulsa. He formerly was with Service Pipe Line Co. and Baroid Sales Division, National Lead Co. A graduate of Purdue, he is chairman of the Tulsa Section's Seventh Annual Corrosion Short Course to be held April 3-5 in Tulsa.

•

**Harry S. Collins** has been appointed general sales manager for Metallizing Company of America. He has been connected for the past 15 years with the Metallizing Engineering Company of Westbury, L. I. General sales offices of the company are located in New York.

•

**David C. Ekey** has been named director of research for Lebanon Steel Foundry, Lebanon, Pa. He recently was assistant professor of industrial engineering at Pennsylvania State University. He is a graduate of Ohio State University.

•

**Gerald G. Lipke,** sales manager for standard products, Hagan Corp., Pittsburgh and his wife were among 44 persons killed November 1 in the crash of an air liner in Colorado. He joined Hall Laboratories, Inc. in 1936.

•

**Lee H. Clark,** general manager of the Pennsylvania Salt Manufacturing Company's Sharples Chemicals Division has been named vice-president of the parent company.

•

**K. T. Snyder,** head of K. T. Snyder Company, 4101 San Jacinto St., Houston has been named national sales agent for the sewer pipe jointing compound manufactured by Gulf States Asphalt Co. and a direct representative for the company in the sale of the company's pipe line enamel. Mr. Snyder formerly was sales manager for Atlas Mineral Products Co.

•

**John O. J. Shellenberger** has been appointed director of marketing of American Paint Co., Ambler, Pa.

•

**Branch M. McNeely, Jr.** has joined the Development and Research Division of The International Nickel Co., Inc., as a member of its Texas Technical Field Section with headquarters at Houston.

•

**Leonard C. Parnell** has succeeded **D. W. Wallace** as manager of American Cast Iron Pipe Company's Minneapolis sales office. Mr. Wallace, who retired October 10 headed the office for 41 years. Mr. Parnell has been with Acipco 20 years, the last six in the Minneapolis office. Mr. Wallace had 46 years of continuous service with the company, having joined the company in 1909, four years after it was organized.

•

**Bill Ramey** has been named sales engineer for Oklahoma and Kansas by Tube-Kote, Inc., with headquarters in Tulsa.

•

**John W. Bizot** is now chief metallurgist at Kaiser Aluminum & Chemical Company's Permanente, California foil mill.

## Rocket Society Elects

Noah H. Davis, manager of the Special Products Dept. of the Becco Chemical Division, of Food Machinery and Chemical Corp., Buffalo has been elected president of the American Rocket Society.

## Lazzara Is Elected

V. S. Lazzara, president of Casting Engineers, Inc., Chicago has been elected president of the Investment Casting Institute.


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# CORROSION ABSTRACTS

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Vol. 12 January, 1956 No. 1


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## 3. CHARACTERISTIC CORROSION PHENOMENA

### 3.5 Physical and Mechanical Effects

3.5.8, 7.8, 6.6.5

**Stress Corrosion in High Tensile Wire.** WALTER O. EVERLING. *Wire and Wire Products,* **30**, 316-319, 346-347 (1955) Mar.

Causes and correction for corrosion of wire for prestressed concrete. Graphs, diagrams, photographs.—MR. 9401

3.5.9, 3.7.1

**Transition Temperature Behavior of Pressure Vessel Steels.** L. J. MCGEADY. Lafayette College. *Welding J.,* **34**, No. 1, 1s-11s (1955) Jan.

PVRC report covers effects of temperature on pressure vessel steels in range from +32° to —50° F., with particular emphasis on transition temperature behavior. Effect of carbon, manganese, silicon and phosphorus contents, ferritic grain size, deoxidation practice, finishing temperature, rolled plate thickness, and normalizing on notch-resistance are covered. Welding, preheating, postheating, and strain-ageing also affect the notched-bar behavior of steel and are taken up briefly. Tables and 55 references.—INCO. 9435

3.5.9, 3.2.1, 3.5.8

**Metallurgical Aspects of Dry Corrosion.** L. B. PFEIL. *Chemistry and Industry,* No. 9, 208-218 (1955) Feb. 26.

Survey of knowledge of oxidation and other attack on metals and alloys at high temperatures. Present theoretical views; alloys of commercial importance; influence of stress on corrosion; effect of structure; carbides in heat-resistant alloys; attack by sulfur-bearing atmospheres; "green rot" of nickel-chromium and nickel-chromium-iron; attack by fuel ash (including vanadium pentoxide attack); repeated heating and cooling with particular reference to scale adhesion. 36 references.—BNF. 9623

### 3.6 Electrochemical Effects

3.6.6, 2.2.2, 2.3.2

**Atmospheric Galvanic Couple Corrosion.** K. G. COMPTON, A. MENDIZZA AND W. W. BRADLEY. *Corrosion,* **11**, No. 9, 383t-392t (1955) Sept.

Tests designed to provide fundamental information explaining the behavior of galvanic couples in the atmosphere are reported. The purpose is to permit prediction of their probable relative behavior. Measurements of weight losses of couples in a marine, an industrial and a severe tropical atmosphere are reported.

Tests involving thin sheet electrode material separated by filter paper saturated with electrolyte are reported. Materials tested include aluminum, magnesium, stainless steel, copper, cadmium, zinc, nickel, tin, chromium, lead, electroplate, silver, low carbon steel and others. Potential measurements and weight loss data are given. Specimens exposed to


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ALL—The Abstract Bulletin, Aluminium Laboratories, Ltd. P. O. Box 84, Kingston, Ontario.

ATS—Associated Technical Services Abstracts, Associated Technical Services, P. O. Box 271, East Orange, N. J.

AWWA—Journal, American Water Works Association, Amer. Water Works Asoc., 521 Fifth Ave., New York 17, N. Y.

BL—Current Technical Literature, Bell Telephone Laboratories, Inc., Murray Hill, N. J.

BTR—Battelle Technical Review, Battelle Memorial Institute, 505 King Ave., Columbus 1, Ohio.

BNF—Bulletin; British Non-Ferrous Metals Research Association. 81-91 Euston St., London NW 1, England.

CBEC—Centre Belge d'Etude de la Corrosion (CEBELCOR), 17 re des Drapiers, Brussels, Belgium.

CE—Chemical Engineering, McGraw Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

EL—Electroplating. 83/85 Udney Park Road, Teddington, Middlesex, England.

EW—Electrical World, McGraw-Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

GPC—General Petroleum Corp. of California. 2525 East 37th St., Los Angeles 11, Calif.

IIM—Transactions, The Indian Institute of Metals, 23-B, Notaji Subhas Road, P. O. Box 737, Calcutta, India.

INCO—The International Nickel Co., Inc. 67 Wall Street, New York 5, New York.

IP—Institute of Petroleum. 26 Portland Place, London W.#1, England.

JSPS—Japan Society for the Promotion of Science, Address: Mr. Hayata Shigeno, Secretary, Committee of Preventing Corrosion, c/o Government Chemical Industrial Research Institute, 1-Chrome Nakameguro, Meguro-ku, Tokyo, Japan.

MA—Metallurgical Abstracts, Institute of Metals, London, England. 4 Grosvenor Gardens, London SW 1, England.

MI—Metallurgia Italiana, Associazone Italiana di Metallurgia. Via S. Paola, 10, Milano, Italia.

MR—Metals Review, American Society of Metals. 7301 Euclid Ave., Cleveland 3, Ohio.

NALCO—National Aluminate Corp. 6216 West 66th Place, Chicago 38, Illinois.

NBS—National Bureau of Standards. Supt. of Documents, U. S. Gov't Printing Office, Washington 25, D. C.

NSA—Nuclear Science Abstracts. United States Atomic Energy Commission, Technical Information Division, Oak Ridge, Tenn.

PDA—Prevention Deterioration Abstracts. National Research Council, 2101 Constitution Ave., Washington 25, D. C.

RM—Revue de Metallurgie, Paris, France. 5 Cite Pigalle, Paris (9e), France.

RPI—Review of Current Literature Relating to the Paint, Colour, Varnish and Allied Industries, Research Association of British Paint, Colour & Varnish Manufacturers, London. Waldegrave Rd., Teddington, Middlesex.

SE—Stahl Und Eisen, Verlag Stahleisen, M. B. H., Dusseldorf, August-Thysen Str. 1. Postscheck Koln 4110, (22a) Dusseldorf, Germany.

TIME—Transactions of Institute of Marine Engineers, 85 The Minories, London EC 3, England.

UOP—Universal Oil Products, 310 South Michigan Ave., Chicago, Illinois.

ZDA—Zinc Development Association. 34 Berkeley Square, London W.1.

the atmospheres show several apparent weight loss anomalies.

Measurements of corrosion currents described provide a quick means for determining probable relative corrosion behavior of couples. Differences between couples "exposed" and "sheltered" are noted. Quantitative data provided are intended to be useful to the design engineer. 9545

3.6.9, 7.7

**Alternating Current Corrosion.** (In German). H. F. SCHWENKHAGEN. *Werkstoffe u. Korrosion,* **6,** No. 2, 63-71; disc., 71 (1955) Feb.

Experimental data for d.c., a.c., and pulsating currents used to account for corrosive effects of stray currents on underground transmission lines. Photographs, tables, graphs, circuit diagram. 7 references.—MR. 9432

## 3.7 Metallurgical Effects

3.7.4, 6.3.6, 3.8.4

**The Crystallographic Dependence of the Oxidation Potential of Solid Copper.** W. E. TRAGERT AND W. D. ROBERTSON. *J. Electrochem. Soc.,* **102,** 86-94 (1955) Feb.

Dependence of oxidation potentials on the various crystallographic planes exposed to the active medium. Tables, graphs. 26 references.—BTR. 9218

3.7.5

**Bright Future Predicted for Vacuum Melted Metals in Chemical Industry.** E. M. MAHLA. E. I. du Pont de Nemours & Company. Paper before Am. Inst. Mining Metallurgical Engrs., Elec. Furnace Steel Conf., Pittsburgh, December 1-3, 1954. *J. Metals* (Trans. AIME), **6,** No. 12, 1370-1371 (1954) December.

Vacuum melting offers promise of improving many properties of steels. Three principal fields of interest, including transverse fatigue properties, high quality surface for film casting wheels and corrosion resistance are discussed. All appear to be associated with the essentially inclusion-free surface of steels. AISI 4340 was used in these series of investigations. Photomicrographs.—INCO. 9154

# 4. CORROSIVE ENVIRONMENTS

## 4.2 Atmospheric

4.2.3, 8.9.4

**Corrosion of Materials Subjected to Locomotive Smoke and Funnel Blast.** T. MARSHALL AND R. M. SINCLAIR. *Corrosion,* **11,** No. 9, 379t-382t (1955) Sept.

A description is given of tests on various constructional materials and protective coatings exposed to smoke, steam and direct funnel blast from coal-burning and oil-burning locomotives. Results indicate that molybdenum-bearing austenitic stainless steel and vitreous-enamelled steel are highly resistant to deterioration in this severely corrosive environment. 9546

4.2.3, 1.2.5

**Exhaust Installations in the Metal Industry.** (In German.) H. MURMANN. *Metall,* **9,** No. 7/8, 278-282 (1955) April.

Methods of removing gases and vapors; separation or absorption of toxic materials; resistant materials of construction for corrosive gases; heating and ventilation of areas subject to exhaust.—BNF. 9650

4.2.3, 5.4.5, 8.9.1

**Solution of Aircraft Wing Exhaust Gas Corrosion Problem is Nearer.** S. K. COBURN. *Corrosion,* **11,** No. 4, 17 (1955) April.

Recently developed protective coatings are discussed which are considered as the final solution of the exhaust gas corrosion problem. Extensive chemical investigation has identified the major exhaust gas deposit as lead bromide, originating in the anti-knock ingredient, lead tetraethyl which contains a small amount of ethylene bromide. It has been postulated that lead bromide undergoes reaction with water leading to the formation of hydrobromic acid and lead oxide. The hydrobromic acid reacts with the electrolytically active aluminum to form the water soluble compound aluminum bromide, a highly deliquescent substance which reacts with any available moisture to form aluminum hydroxide while regenerating an equivalent quantity of hydrobromin acid. An obvious procedire for overcoming this type of corrosion is the use of a protective film with adequate chemical and physical properties. At present polyester resins are being tested with encouraging results.—ALL. 9400

4.2.3, 5.8.2

**Laboratory Studies on Use of Coal-Tar Bases As Inhibitors of Corrosion by Flue Gases.** R. W. KEAR. *J. Applied Chem.,* **4,** Pt. 4, 674-679 (1954) Dec.

Investigation of use of coal-tar bases as inhibitors of the corrosion of steel surfaces by flue gases containing sulfur trioxide. In first series of tests, bases were sprayed into a town's-gas flame with object of minimizing the formation of sulfur trioxide in the combustion process; in second series, bases were sprayed into the gas stream with object of depositing a protective film on steel surface. Addition to the flame of up to 12 g/h of bases reduced corrosion and rate of sulfuric acid deposition from gases containing 0.005 percent of sulfur trioxide (dew-point 138°) at all surface temperatures below the dew-point. When a liquid film was deposited on the steel, surface corrosion at temperatures below 117° was decreased, but some corrosion was induced at temperatures above the dew point, i.e. 136°. Graphs, diagrams and 9 references.—INCO. 9139

## 4.3 Chemicals, Inorganic

4.3.3, 6.3.14

**The Corrosion of Tin by Aqueous Solutions of Ammonia.** S. C. BRITTON AND D. G. MICHAEL. *J. Applied Chem.,* **5,** 1-9 (1955) January.

Conditions for prevention of attack; inhibitor additions. Tables, graph. 5 references.—BTR. 9234

4.3.2

**Hydrofluoric Acid Handling.** *Ind. Chemist,* **30,** No. 359, 609-610 (1954) Dec.

Uses, limitations and preferred fabrication techniques for various materials of construction with both aqueous and anhydrous acids. Lead, nickel, copper, Monel, Chlorimets, Durimet 20, etc.; carbon and graphite, rubber and plastics.—BNF. 9734

4.3.2, 3.5.2, 3.5.11

**The Special Importance of Flow Rate on Sulfuric Acid Corrosion.** (In German). H. W. VAN DER HOEVEN. *Werkstoffe u. Korrosion,* **6,** No. 2, 57-62; disc., 62 (1955) Feb.

Effects of velocity and accumulation of corrosion products in the corrosive agent on aluminum-nickel bronze and carbon steel. Diagrams, micrographs.—MR. 9286

## 4.5 Soil

4.5.1, 6.4.2

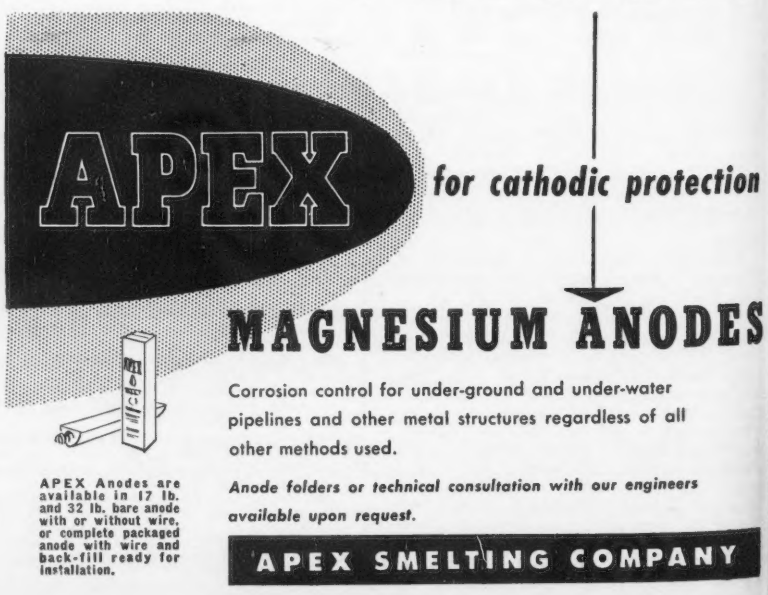
**Soil Corrosion of Aluminum.** (In German). TIHOMIL MARKOVIC. *Werkstoffe u. Korrosion,* **6,** No. 2, 84-86 (1955) Feb.

Effects of air and water in the soil on corrosion rates. Graphs. 6 references. —MR. 9416

4.5.2, 6.4.2

**The Influence of Periodic Ventilation on the Soil Corrosion of Aluminium.** (In German.) T. MARKOVIC AND M. KARSULIN. *Werkstoffe u. Korrosion,* **6,** No. 1, 6-8 (1955) Jan.

In the experiments conducted by the authors two types of galvanic couples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were used. First the electrodes were platinum and aluminum; secondly, both electrodes were aluminum, one with a rough, the other with a smooth surface. In both cases the electrolyte was damp soil. The investigation demonstrated that aluminum behaves either passively or actively in accordance with the degree of satuation of the soil with water. An increase of the water content of the soil causes an increase in the activity of the aluminum in the first type of galvanic couple and also in the activity of the smooth faced aluminum electrode in the second. The aluminum suddenly becomes passive when the saturation point is reached. The ratio of the water to air (oxygen) in the soil determines the rate of corrosion for aluminum in soil. Sodium chloride, potassium chloride or magnesium chloride present in the electrolyte do not affect this type of corrosion. If the soil is in an atmosphere of nitrogen, the aluminum electrode always remains passive. Periodic saturation of the soil with water was followed by corresponding periodic variations in the character of the corrosion.—ALL. 9501

4.5.3

**Fundamentals of Corrosion Surveys.** M. E. PARKER. *Petroleum Engr.*, **27**, No. 3, D22-D27 (1955) Mar.

Elements of importance to corrosion surveys include gathering and study of available data, types of tests, determining damage, planning protection, and determining costs and economics. Graphs and diagrams.—INCO. 9626

4.5.3, 2.3.5

**Design and Application of Corrosion Current Measuring Instruments.** DONALD L. HAM. *Corrosion*, **11**, No. 8, 343t-346t (1955) Aug.

The three principal kinds of instruments used to measure currents associated with corrosion are described and their circuit diagrams illustrated. Considerations involved in selecting the correct instruments for several kinds of current measuring problems are reviewed and the capacities and limitations of the applicable instruments evaluated. Examples of typical uses are given. 9554

4.5.3, 5.2.1, 3.6.6

**Geometric Factors in Electrical Measurements Relating to Corrosion and Its Prevention.** W. J. SCHWERDTFEGER AND IRVING A. DENISON. *Corrosion*, **11**, No. 10, 423t-432t (1955) Oct; *J. Research Nat'l Bur. Standards*, **54**, No. 2, 61-71 (1955) Feb.

The "electrical boundary" of a galvanic couple immersed in an aqueous medium, when corroding normally and also when corrosion is stopped by cathodic protection, is discussed in the


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light of present theory. Experimental data, consisting of potential measurements made on bimetallic couples in an undestricted medium producing relatively little polarization and also one producing considerable polarization, are compared with theoretical data. The electrical boundary is theoretically defined and experimentally verified for model galvanic couples having bimetallic electrodes, one couple simulating line electrodes and the others having electrodes made of longitudinal cylindrical segments arranged in three anode-to-cathode area ratios. The effect on potential measurements as a result of interference to the normal flow of galvanic and external currents is also shown by experimental data. The results of this study indicate that geometric factors should be given consideration in making potential measurements on subsurface structures of similar configuration such as cylindrical tanks and pipelines. 9726

## 4.7 Molten Metals and Fused Compounds

4.7, 1.6

**A Report on the Proceedings of the Liquid Metal Utilisation Conference.** (Atomic Energy Research Establishment), 1953. C. G. BANISTER AND OTHERS. A.E.R.E. Report X/R 1381, 1954, 84 pp. Available from H. M. Stationery Office.

This is a report of a conference convened by A.E.R.E. and held in Abingdon on May 16th, 1953. After a brief introductory statement by S. G. Bauer (including notes on American practice) includes papers by W. B. Woollen, "Design and Operation of Apparatus for Handling Liquid Sodium and Similar Fluids"; D. A. Watts, "Electromagnetic Pumping of Liquid Metals"; C. D. Boadle, "The Use of Liquid Metals for High Temperature Heat Transfer" (includes a table of physical properties at 400° C. of liquid metals, e.g., sodium sodium-potassium mercury, lead-bismuth eutectic, gallium, lithium; W. B. Hall, "Heat Transfer Experiments with Liquid Sodium"; R. L. J. Hayden, "The Design and Construction of Sodium-Steam Superheater Test Plant"; J. E. B. Perkins, "A Study of Sodium Heated Steam Generating Plant"; R. J. Terrell, "The Application of Liquid Metals to Reheating in Steam Turbine Plant."—BNF. 9797

# 5. PREVENTIVE MEASURES

## 5.1 General

5.1, 1.6

**Techniques of Plant Maintenance and Engineering, 1954.** Book, 1954, 291 pp. Clapp and Poliak, Inc., 341 Madison Avenue, New York.

Proceedings of the technical sessions held at the 5th National Plant Maintenance and Engineering Show, Chicago, January, 1954. The subjects dealt with include the planning of maintenance work for large and small factories, management methods, industrial hygiene, corrosion control and prevention, waste disposal, cost of maintenance, lubrication and bearings, etc.—BNF. 9774

5.1, 6.2.3

**Electroplating for Shelf Life.** J. B. MOHLER. *Metal Finishing,* **53,** No. 3, 64-67, 72 (1955) Mar.

General discussion of durability, degree of protection, appearances and cost of various protections for mild steel: oil, phosphating, vapor inhibitors, packing in grease, strippable plastic coatings; zinc, tin, copper/nickel/chromium, copper, cadmium or lead plated coatings.—BNF. 9614

## 5.2 Cathodic Protection

5.2.1

**Application of Cathodic Protection in the Chemical Industry.** (In German.) W. RAUSCH. *Werkstoffe u. Korrosion,* **6,** No. 4, 189-196; disc., 197-198 (1955) April.

After a brief general introduction, practical criteria for complete protection, current required, sources of current (external current, zinc or magnesium-alloy anodes); protection of buried pipelines with anodes, and of plant (coolers, condensers, hot water tanks) internally. 6 references.—BNF. 9630

5.2.1, 7.10

**Cathodic Protection of Marine Installations.** H. M. POWELL. *Corrosion Prevention & Control,* **2,** No. 2, 30-31, 62 (1955) Feb.

Chief consideration is given to cathodic protection of fixed structures such as steel jetties, piers, bridges, sheet steel piling caissons and dock gates. Choice between power impressed and sacrificial anode systems is entirely dependent upon the local conditions. In marine as in buried installations, cathodic protection is most economical when supplementing a good coating.—INCO. 9642

5.2.2

**Cathodic Protection of Treating Equipment.** W. C. KOGER. *Petroleum Engineer* (Management Ed.), **27,** 92B-94B (1955) Mar.

Operating life of emulsion reduction equipment can be substantially extended through the installation of magnesium alloys. Graphs, photographs, diagram, tables.—MR. 9418

5.2.3, 7.7

**A Technique for Installing Carbon Anodes in Cable Ducts.** Topic of the Month. EDWARD J. DOYLE. *Corrosion,* **11,** 17-18 (1955) Feb.

Development and use of graphite anodes in cathodic protection of underground cables. Diagram, photographs.—BTR. 9366

## 5.3 Metallic Coatings

5.3.4, 6.3.6

**The (Tin) Plating of Powder-Metallurgy Bronze Parts.** E. V. RAYMOND, R. T. FOLEY AND W. L. CHU. *Plating,* **42,** No. 2, 150-151 (1955) Feb.

An investigation of various methods described in the literature as being free from "spotting out" troubles (corrosion by absorbed electrolyte); these methods include cold working of the surface, immersion plating, impregnation with silicones, volatilization of residual salts, etc. Preferred method is to impregnate with lubricating oil prior to tin plating.—BNF. 9631

5.3.4

**Some Aspects of the Electrodeposition of Titanium and Zirconium Coatings.** R. H. CREAMER, O. H. CHAMBERS AND C. E. WHITE. U. S. Bur Mines Rept. of Investigations No. 5093, December, 1954, 39 pp.

Attempts to electroplate titanium and zirconium from various aqueous, nonaqueous, and fused salt electrolytes. Only fused salt electrolytes produced metal deposits but no electrolyte was completely satisfactory. Earlier work and problems of plating these metals are discussed in detail. 28 references.—BNF. 9773

5.3.4

**Brass Plating.** K. G. COMPTON, R. A. EHRHARDT AND G. BITTRICH. *Plating,* **41,** No. 12, 1431-1439 (1954) Dec.; *Proc. Amer. Electroplaters' Soc.,* 41st Ann Convention, 1954, 267-275.

Investigation of effect of variations in bath composition and operating conditions on the composition of the brass deposits made at Bell Telephone Laboratories with particular reference to the continuous plating of wire for rubber adhesion.—BNF. 9776

5.3.4

**Mode of Action and Preparation of Fluxes for Hot-Dip Galvanizing.** J. HILLE. *Arch. Eisenhuttenw.,* **25,** No. ½, 19-31 (1954) Jan.-Feb.; Translation: Brit. Non-Ferrous Metals Res. Assoc., Serial No. 39,476a.

Report No. 6 of the Galvanizing Trade Committee of the Verein Deutscher Eisenhuttenleute and the Forschungsgesellschaft Blechverarbeitung. Chemical and physical properties of fluxes for hot-dip galzanizing; mode of action of fluxes in aqueous solution and in the molten state; correct choice of fluxes and best method of preparation for wet and dry galvanizing; possibilities of wet galvanizing with zinc baths containing aluminum; choosing fluxes for hot-dip tinning and lead coating. Discussion on this paper appears in *Arch. Eisenhuttenw.,* **25,** No. 9/10, 405-407 (1954) Sept.-Oct.—BNF. 9733

5.3.4

**Zinc Plating Troubles.** J. H. COLLINS. *Product Finishing,* **7,** No. 9, 50-54 (1954) Sept.

The advantages of electrodeposited zinc coatings on iron and steel are briefly outlined and the conditions for using acid or cyanide plating solutions are described. Tables indicate the possible causes of defects that may arise in the plating and suggest remedies.—ZDA. 9712

5.3.4

**Silver Plating.** Brochure, December, 1954, 35 pp. Johnson Matthey & Co. Ltd., 73-83, Hatton Garden, London, E. C. 1.

Practical details of silver plating; cleaning copper, copper alloys, iron and steel prior to plating, undercoats, quicking and striking, other preliminary dips; anodes, operating conditions, vat and barrel plating, bright silver, rapid silver plating, masking; finishing; plating troubles.—BNF. 9694

## 5.4 Non-Metallic Coatings and Paints

5.4.5

**Instruments for Measuring Gloss, Hiding Power and Colour of Paint Films.** D. B. JUDD. *Am. Paint J.,* **38,** No. 41, 66-68, 70, 72, 74, 76 (1954).

The fundamental principles on which

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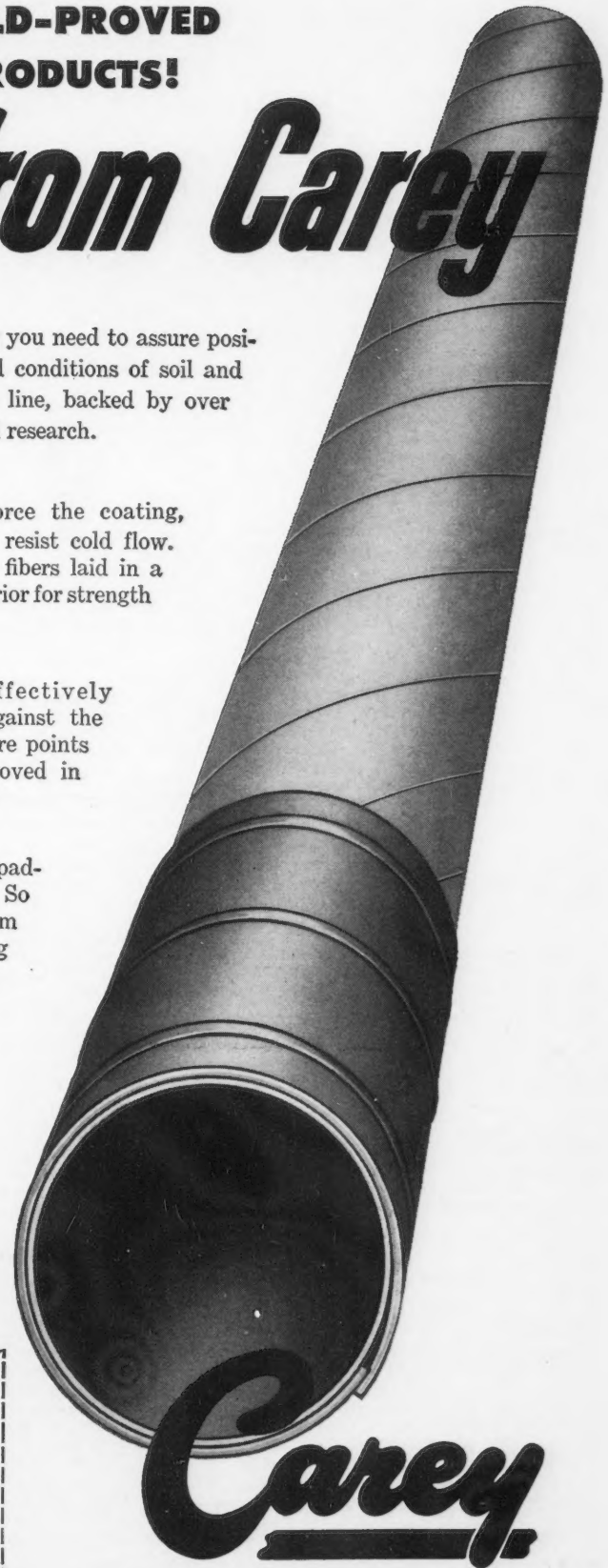


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these measurements are based are discussed.—EL. 9704

5.4.5, 1.2.2

**Economic Justification of Protective Coatings.** CLARENCE C. HARVEY. Paper from "Surface Protection Against Wear and Corrosion," 1954, 295-304 (published by American Society for Metals, Cleveland, Ohio).

Coating costs compared with cost of atmospheric corrosion. Graphs, tables.—BTR. 9696

5.4.5, 1.2.2, 1.6

**Measurement and Control of Industrial Paint Finishing Costs.** Brochure, November 10, 1954, 60 pp. Published by Imperial Chemical Industries Ltd. (Paints Division), Slough, Bucks.

Report of conference convened by the Paints Division. Contains three papers by individual authors on measurement and control of costs and on the foreman's part in cost control.—BNF. 9736

5.4.5, 5.6.3

**Continuous Strip Galvanizing in Argentina.** C. R. W. HUGHES. *Sheet Metal Inds.*, **31**, No. 325, 359-366 (1954) May.

A detailed and well illustrated description of the Sendzimir widestrip galvanizing plant installed at the works of the Anglo-Argentine Iron Co. Ltd., Buenos Aires. A special protective film is used over the strip surface to prevent corrosion during transit from the cold-reduction mills to the galvanizing bay, since periods as long as six months may elapse between rolling and processing. The coating is removed partly in the cleaning tanks and partly by evaporation-combustion when the strip passes through the preheating furnaces.—ZDA. 9741

## 58. Inhibitors and Passivators

5.8.3

**Inhibition and Inhibitors.** (In German). HELLMUTH FISCHER. *Werkstoffe und Korrosion*, **6**, No. 1, 26-31; disc., 31-32 (1955) Jan.

Discusses the mechanism of physical and chemical inhibition, its existence and use. Tables, diagrams. 10 references.—BTR. 9368

5.8.3

**Thermodynamic Considerations of Surface Regions.** Adsorbate Pressures, Adsorbate Mobility, and Surface Tension. E. A. FLOOD AND M. HUBER. *Can. J. Chem.*, **33**, 203-214 (1955) Feb.—BL. 9372

5.8.3, 5.8.2

**The Pertechnetate Ion as an Inhibitor of the Corrosion of Iron and Steel.** G. H. CARTLEDGE. *Corrosion*, **11**, No. 8, 335t-342t (1955) Aug.

Theoretical consideration of possible mechanisms to account for the action of inorganic corrosion inhibitors of the $XO_4^{n-}$ type led to the discovery that the pertechnetate ion, $TcO_4^-$, inhibits the corrosion of iron and carbon steels in aerated water at temperatures from 23 to 250° C., which was the highest temperature investigated. The chemistry and nuclear properties of technetium are such as to make it very useful in studying the inhibitory process. Thus, it has been shown that inhibition may be achieved without precipitating more than radiochemical traces of reaction products on the metal and even this amount is shown to be most probably of secondary origin. Exposures of two years have not been attended by a continuous increase in the amount of precipitated technetium. It was found that even at 250° C. 5 ppm of technetium ($5 \times 10^{-5} f$ $KTcO_4$) in distilled aerated water effectively inhibited the attack on an SAE 1010 steel. The inhibition depends upon the maintenance of some minimum concentration of dissolved pertechnetate, the amount being dependent upon the nature of the metal and its surface activity. The evidence points to a weak, reversible adsorption of the inhibitor ion as the source of inhibition. The perrhenate ion, $ReO_4^-$, is very similar to the pertechnetate ion in geometry and charge, yet it was found to have no inhibitory properties under any of several conditions studied. The observations make it clear that inhibition arises from some intra-ionic property and it is tentatively suggested that this is a degree of internal polarity sufficient to induce a short-range electrostatic polarization at the interface, whereby the activation energy for the cathodic part of the corrosion process is increased. 9540

5.8.3, 6.2.2

**Effect of Oxygen, Chlorides and Calcium Ion on Corrosion Inhibition of Iron by Polyphosphates.** H. H. UHLIG, D. N. TRIADIS, AND M. STERN. *J. Electrochem. Soc.*, **102**, 59-66 (1955) Feb.

Corrosion data indicate that sodium polyphosphates inhibit by favoring passivation by absorbed oxygen. A critical supply of oxygen is required. Diagram, graphs, table. 24 references.—BTR. 9282

## 5.9 Surface Treatment

5.9.2, 7.6.4

**Chemical Cleaning of Boilers.** (In Japanese). H. TAMURA AND S. OONISHI. *Corrosion Engineering*, **3**, No. 6, 32-35 (1954) December.

Inhibited hydrochloric acid is generally used for removing rust from new boilers and insoluble deposit such as scale from old ones. Addition of phosphoric acid or its salts to the inhibited acid improves the solubility of metal oxides or salts, and also anticorrosive power of the surface after cleaning. So marine boilers can be cleaned economically even at room temperatures. Thiourea and its derivatives inhibit the corrosiveness of this type of acid and addition of furfural or wetting agents lowers the rate of attack. Details of cleaning methods and results with inhibited reducing solution have been reported in this paper.—JSPS. 8805

5.9.2.,5.9.3, 8.8.5

**Chemical or Mechanical Descaling of Steel Bars?** (In German). OTTO PELTZER. *Stahl und Eisen*, **75**, No. 3, 129-140 (1955) February 10.

Report No. 21 of the Bright Drawn Steel Bar Committee of the Verein Deutscher Eisenhuttenleute. Chemical descaling and its accompanying phenomena. Future laws on water economy and their effects on the pickling plants. Mechanical descaling of rolled products and its possibilities. Descaling by shot blasting, particularly of bright-drawn steel bars. Types of descaling machines working with blasting media and their modes of operation. Operational cost. Examples taken from the practice as a basis for the estimation of cost when descaling steel bars. Calculation of the cost of operation of a regeneration plant for spent pickling solutions. Comparison of the operational cost of mechanical descaling bright-drawn steel bars with the pickling cost and additional cost of spent pickling solution regeneration.—SE. 9217

5.9.2

**Alkaline Degreasing of Metal Surfaces.** M. KIKUCHI AND K. OKI. Govt. Chem. Ind. Research Inst., Tokyo. *Repts. Govt. Chem. Ind. Research Inst., Tokyo*, **49**, 61-64 (1954).

As tested with soiled copper plates, three commercial alkaline degreasers (containing 3 or 4 of sodium hydroxide, sodium carbonate, sodium monobasic orthophosphate, sodium cyanide and soap) cleaned the surface more efficiently (estimated from the area wettable with water over that not so wettable) in about 30 min., when 5 g/l nonionic polyethylenelaurate was added, which decreased the surface tension markedly. The addition of ionic surface-active agent such as sodium isopropylnaphthalene-sulfonate decreased the surface tension without affecting the cleaning efficiency.—EL. 9118

5.9.3, 6.4.2

**Granal: a New Abrasive for Surface Treatment of Aluminium Parts.** (In German and French.) H. P. HABERLIN AND H. KELLER. *Aluminium Suisse*, **4**, No. 4, 136-137 (1954) July.

Granal is a new aluminum alloy abrasive (composition unspecified), prepared by a pouring method. It can be obtained in various grit sizes for use in standard sand blasting machines. Claimed to be preferable to silica sand, with which there is danger of silicosis, or iron powder, which may set up galvanic corrosion or cause rust spots on the surface.—BNF. 9697

5.9.4

**How to Obtain High Quality Carburized Cases.** H. E. MANSFIELD. *Materials & Methods*, **41**, No. 1, 134-137 (1955) Jan.

Practical notes on case hardening for optimum results are given. Degree of temperature uniformity, controlled furnace atmosphere, and cooling and hardening cycles determine the uniformity of results. Retained austenite, sub-surface scale, and structures containing excessive carbides cause a decrease in the life of the carburized part. Photomicrographs.—INCO. 9436

5.9.4

**A New Surface Finishing Process for Aluminium.** J. J. POLLING AND A. CHARLESBY. *Product Finishing*, **8**, No. 4, 50-55 (1955) April.

Individual crystals of the metal are revealed by etching at room temperature in a mixture of hydrofluoric acid/hydrochloric acid/nitric acid/water (ratio of 3:9:3:5) and give the surface a scintillating appearance with a wide range of attractive and accurately reproducible colors. The etched surface is anodized in dilute ammonium borate or ammonium tartrate and a thin semi-reflecting layer of aluminum, silver or gold is applied by vacuum evaporation. Finish has excellent corrosion resistance; has also been applied to tantalum and zirconium.—BNF. 9591

5.9.4, 6.4.4

**Electrolytic Coatings on Magnesium Base Alloys from Alkaline Chromate Solutions.** F. OGBURN, H. I. SALMON AND M. L. KRONENBERG. *Plating*, **42**, No. 3, 271-274 (1955) Mar.

Compares the three available processes:

low-voltage alkaline chromate, HAE, and acid chromate. Bath composition, operating conditions, coating properties and distribution, corrosion resistance, chemical composition, subsequent treatments, etc.—BNF. 9612

5.9.4, 6.3.6

**Investigation of the Mechanism of Electropolishing of Metals. Part I. Electropolishing of Copper at Low Current Densities.** (In Russian.) V. A. DMITRIEV. *J. Applied Chem., USSR* (Zhur. Priklad. Khim.) **27**, No. 8, 891-900 (1954) Aug.

Electropolishing of horizontal plates of cold-rolled or annealed copper in phosphoric acid, the changes at the surface being observed microscopically during the process. Polishing began only when a minimum anode potential had been attained and the anodic layer of electrolyte was saturated with dissolution products; current density was not important.—BNF. 9770

## 5.11 Design—Influence on Corrosion

5.11

**Design Against Atmospheric Corrosion.** HENRY T. RUDOLF. *Corrosion*, **11**, No. 8, 347-350t (1955) Aug.

Specific recommendations for construction of metallic surfaces exposed to corrosion are made. The author points out total exposed areas may be reduced by adopting the proper shapes of structural members, by enclosing with planar plates structures including angles and braces. Seal welding is recommended.

The design engineer is warned to keep in mind structures exposed to atmosphere ultimately require surface preparation and that an effort should be made to minimize inaccessible areas. Consideration should be given to the need for ultimate painting by providing as many plane surfaces as possible. Welding is favored over riveting. Specific recommendations are made concerning design which offer the best possible way of minimizing corrosion damage. 9551

## 6. MATERIALS OF CONSTRUCTION

## 6.2 Ferrous Metals and Alloys

6.2.3, 3.7.3, 5.12

**Quenching Improves Atmospheric Corrosion Resistance of Mild Steel.** M. HASEGAWA. *Corrosion Engineering* (Japan), **3**, No. 5, 30-33 (1954) October.

Quenching of low carbon steels such as mild or dead soft steel, has hardly been applied in industry. The author found that atmospheric corrosion resistance of these materials was improved with rapid cooling from austenitic range.

Results are summarized as follows: 1) The corrosion resisting property appears only on the surface. 2) The improved property is only recognized under atmospheric tests. 3) In industrial applications, the carbon content of materials should be less than 0.15 percent, otherwise the quenching treatment will injure mechanical properties. 4) It is concluded that this phenomenon is caused by dissolving impurities or alloying elements into ferrite.—JSPS. 9183

6.2.3, 7.10

**Corrosion Problems in Hospital Practice.** S. J. HOPKINS. *Corrosion Technology*, **1**, No. 9, 330-332, 343 (1954) November.

Discusses the use of carbon steel for surgical cutting instruments, prevention of corrosion by oxide film and protection by various inhibitors including sodium benzoate, sodium nitrite and an oily product known as A.C.10. Influence of dust on initiating corrosion is considered. Photomicrographs.—INCO. 9135

6.2.2

**Strength of White Irons in the Temperature Range of Hot Tearing.** J. P. FRENCK AND R. W. HEINE. Paper before Am. Foundrymen's Soc., 58th Ann. Mtg., Cleveland, May 8-14, 1954. *Am. Foundryman*, **25**, No. 3, 68-72 (1954) March.

Tensile strength of white irons studied varies from nothing to several hundred pounds at temperatures of 2030-2200 F; contraction of a few thousandths of an inch can cause complete tearing. Graph showing the total contraction rate of casting as a function of the percentage of carbon in the iron is included. Diagram, tables, graphs, photomicrographs and 3 references.—INCO. 9237

6.2.3, 3.7.3

**The Nominal Cleavage Strength of Steel.** (In Swedish.) TORE NOREN. *Jernkontorets Annaler*, **139**, No. 3, 141-153 (1955).

Determination by exposing test pieces with weld-deposited brittle surface layers to increasing tensile strength. Diagram, photographs, graphs, table.—BTR. 9658

6.2.5

**Hard Manganese Cast Steel.** E. PIWOWARSKY AND H. L. ROES. *Giesserei*, **41**, 357-369 (1954) July 8.

Commentary-review of manufacture and metallurgy of manganese steels, with notes on effects of individual elements, microstructures, heat-treatment, determi-

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E-31

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nation of castability, followed by results of the authors' own investigations on the effect of phosphorus and influence of casting temperature and wall thickness. Raising the phosphorus content results in deterioration of notch-impact strength, bending strength, and modulus of elasticity, as a result of phosphide precipitation, but hardness increases. Microstructures of high phosphorus-manganese steels, preparation of test specimens in form of rods of diameters up to 180 mm., and heat-treatment are discussed. Increasing wall thickness of casting results in increased grain size. At approximately 1550°, effects of casting temperature and wall thickness coincide, so that grain shape alters suddenly from a globular to a dendritic form, e.g. from a fine to a coarse-grain structure. The marked carbide inclusions in the thicker specimens raise problems as regards hardenability of subsequent heat-treatment. Pure austenitic structure was observed even in specimens 180 mm. thick. Casting temperature is the most important factor as regards crystallization and grain structure. The lowest casting temperatures gave the most fine-grained structure. Increase in grain size appears to be limited at casting temperatures above 1700° and casting thicknesses greater than 60 mm., up to which continuous coarsening of the grain and increasing carbide precipitation must be expected. Effects of heat-treatment on bending strengths are given.—INCO. 8842

## 6.3 Non-Ferrous Metals and Alloys—Heavy

6.3.6, 3.8.4

**Anodic Behavior of Copper in HCl.** LEE STEPHENSON AND J. H. BARTLETT. University of Illinois. *J. Electrochem. Soc.*, **101**, No. 11, 571-581 (1954) Nov.

Anodic behavior of copper in 2N hydrochloric acid has been studied by both electrical and optical methods. The temporal behavior of current and voltage have been found, as well as the current vs. voltage characteristics. The anode surface has been observed both visually and photographically with the aid of conventional microscopes and the anolyte has been photographed cinematographically using a Schlieren microscope.

When the current is turned on, a layer, probably cuprous chloride, starts to form at random nucleation spots on the anode. This grows until the whole anode is covered, at which time the current drops abruptly. Up until this time the anolyte becomes less concentrated, but the concentration may increase again after the current has become low.

The anode-calomel voltage may be written as $V = \varepsilon(i) + ir$, where $\varepsilon(i)$ becomes constant at high current densities. The values of $\varepsilon(i)$ have been found by both the interruption and the direct method, and there appear to be at least four of physical significance. These values are —0.35, —0.27, —0.05, and +0.11 v.

In general, the current drops twice before reaching its minimum value.. If $t_1$ is the time from the make to the first drop, and if $Q = \int_0^{t_r} i\,dt$, and if $i_o$ is the "initial" current after the make, then empirically $Q = 24(i_o - 0.70)^{-0.53}$, where $i_o$ is in ma.

The anode layer is about $3\mu$ thick in the steady state. When the circuit is broken, $r$ and $\varepsilon$ change rather rapidly (in about 0.1 sec.), but the layer dissolves off slowly.—INCO. 8707

6.3.8

**Productions and Applications of Super-Purity Lead.** (In Italian). L. FAGNANI. *Metallurgia Italiana*, **46**, No. 6, 211-220 (1954) June.

Effects of impurity elements on mechanical and corrosion properties of lead; uses of the various commercial types of very pure lead; chemical industry, accumulators, anodes in electrolytic extraction of zinc, alloys for cables and solders, oxides for pigments. Brief reference to production by A. Tonolli and Co.—BNF. 8518

6.3.9, 3.2.3, 3.8.4

**High Pressure Oxidation of Metals.** Technical Report No. 6. Molybdenum in Oxygen. ROBERT C. PETERSON AND W. MARTIN FASSELL, JR. Utah Univ., Contract DA-04-495-ORD-237, September 1, 1954, 22 pp.

The temperature and pressure dependence of the reaction of molybdenum in oxygen was investigated from 525 to 700 C at pressures from one atmosphere to 47.6 atms. (700 psia). Molybdenum was found to oxidize linearly from 525 to 650 C at all pressures investigated. No dependence was observed from 525 to 550 C at pressures above one atmosphere. From 550 to 700 C the oxidation rate of molybdenum was dependent on oxygen pressure. The pressure dependence from 550 to 650 C may be expressed by $v = k'\theta$ where $k'$ is the specific rate constant and $\theta = (k_1CO_2/(1 + k_1CO_2)$ where $k_1$ is the equilibrium constant for the adsorption of oxygen at the surface site of reaction. An unusual pressure sensitive transition from a linear rate to some type of protective rate was observed at 650 to 700 C (auth.)—NSA. 8597

6.3.10, 3.5.8, 3.5.9

**Effects of Cyclic Overloads on the Creep Rates and Rupture Life of Inconel at 1700 and 1800 F.** R. H. CAUGHEY AND W. B. HOYT. Paper before Am. Soc. Testing Materials, Symp. on Effect of Cyclic Heating and Stressing on Metals at Elevated Temperatures, 57th Ann. Mtg., Chicago, June 17, 1954. ASTM Special Technical Pubn. No. 165, 1954, 79-102; disc., 103-104.

A series of creep-rupture tests was conducted at 1700 and 1800 F on coarse-grained Inconel to determine effect of cyclic mechanical and thermal overloads. "Over conditions" were applied for a single continuous time interval and also for several cyclic time intervals of equal duration. Test values obtained by Inco from high-temperature tests under constant conditions were used as a basis of comparison. Data on elongation and reduction of area after failure were obtained for all specimens and specimens were examined microscopically after testing for evidence of surface cracking, and structural instability. Individual tests are described and a summary of test conditions is tabulated. Creep-rupture test data at 1800 F, obtained by Inco, are tabulated and plotted on log-log coordinates. Graphs, tables, photomicrographs.—INCO. 9275

6.3.10, 3.7.2

**Investigation of Nickel-Aluminium Alloys Containing from 14 to 34% Aluminium.** W. A. MAXWELL AND E. M. GRALA. U. S. National Advisory Committee for Aeronautics, Tech. Note 3259, 1954, 42 pp.

The following nickel-aluminum alloys were prepared by casting in argon: 14.0, 15.5, 17.5, 21.5, 25.0, 28.0, 30.0, 31.5 and 34.0 percent aluminum. All alloys, except those containing 31.5 and 34.0% aluminum, yielded sound castings. The 17.5% aluminum alloy had good hot-workability and attractive mechanical properties. It was therefore investigated further, and the following properties were determined: a) as-cast, U.T.S. 79,600 lb./in.$^2$ with 1.2% elongation at room temperature; 50,000 lb./in.$^2$ with 2.9% elongation at 1500 F (815 C); b) hot-rolled, U.T.S. 51,000 lb./in.$^2$ with 3.9% elongation at 1500 F and 21,000 lb./in.$^2$ with 25% elongation at 1800 F (980 C); c) stress-rupture properties at 1350 F (730 C) were better than those of Inconel, but worse than those of Inconel X; d) room-temperature impact strength 3.5 (notched) and 10.3 (unnotched) in.-lb.; and e) oxidation-resistance at 1800 F similar to that of Nichrome. Heat-treatments revealed structural changes, including a martensite-type transformation, which is expected to facilitate the creation of a fine dispersion of the precipitated phase ($Ni_3Al$) in the matrix (NiAl) after a suitable aging treatment. The 17.5% aluminum alloy is regarded as worthy of consideration as a basic composition for high-temperature commercial alloys.—MA. 9141

6.3.10, 3.8.4

**On the Mechanism of Nickel Oxidation at Low Temperatures.** (In German). K. HAUFFE AND B. ILSCHNER. *Z. Elektrochem.*, **58**, No. 6, 382-387 (1954).

On the basis of experimental data taken from various publications, the reaction between oxygen and nickel surfaces at temperatures of the order of 80-500 K can be described as follows: The oxygen atoms adsorbed on the metal surface attract and incorporate electrons from metal atoms in their outer shells. The conductivity of the metal is decreased and a double electric layer is formed on the surface. The electric fields created between the adsorbed oxygen atoms and the attracted electrons cause local disruptions in the metal lattice which develop into nuclei for oxide formation. These nuclei expand with considerable velocity and cover the surface with an uneven oxide film. The oxide lattice is gradually built up. The velocity of the reaction is determined by the limited supply of new electrons. It is assumed that most electrons traverse the oxide layer by a tunnel effect, which can explain the logarithmic oxide growth law observed. When layers several atoms thick have been built up, the transport of ions slows down rapidly. The supply of new electrons, however, again increases and produces an equilibrium at the surface which practically stops the reaction.—PDA. 9137

# 7. EQUIPMENT

## 7.1 Engines, Bearings and Turbines

7.1, 5.3.2

**Overlay Bearings.** J. B. MOHLER. *Metal Ind.*, **86**, No. 18, 375-378 (1955) May 6.

Among multiple layer bearings now in use are a lead alloy overlay cast on a sintered copper-nickel layer, and lead alloy and tin overlays electro-deposited on sintered or cast copper-lead or bronze. Original Babbitt-lined bronze-backed bearing or bushing is still used in many applications, and micro-bearing consisting of Babbitt lining 0.002-0.005 in. thick on steel back is popular although limiting load capacity is below that required in many modern high load engines. Results of tests on bearings of sintered 65-35 copper-lead alloy on steel back, without

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overlay, and with lead or tin overlays, are discussed and tabulated. Insufficient corrosion resistance of lead overlay is corrected by adding tin and by use of a dam, usually of nickel, to inhibit loss of tin from overlay. Most of the general corrosion problem has been solved by the use of inhibited oils. Illustrations, 10 references.—INCO. 9619

7.1, 5.3.2

**Chromium Plating of Engine Cylinders Can Slash Wear Rates, Ups Economy.** R. PYLES. Van Der Horst Corp. of Am. *Power*, **99**, No. 6, 132-133 (1955) June.

Chromium-plating of internal combustion engine cylinders, proved in aircraft and submarine engines, is now used in locomotive diesels, marine engines, heavy-duty automotive diesels, and many stationary engines. Porous chromium is produced by electrolytic or chemical action on chromium plate on a smooth-honed bore. Chromium bore may be pre-roughened, knurled or tooled before dense chromium is deposited on it. Photomicrographs show porosity types on different metal surfaces and effects of service. In normal engine service, porous chromium-plated cylinders give wear rates 1/3 to 1/10 those of cast iron and steel, whether or not they have been heat-treated or hardened.—INCO. 9633

7.1, 6.5, 4.2.3, 3.5.9

**Effect of the Composition of Gas-Turbine Alloys on Resistance to Scaling and to Vanadium Pentoxide Attack.** G. T. HARRIS, H. C. CHILD AND J. A. KERR. *J. Iron and Steel Inst.*, **179**, 241-248 (1955) Mar.

Scale resistance in moving air of some typical gas-turbine alloys with and without coatings of vanadium pentoxide studied throughout their useful temperature range. Tables, graphs, diagrams. 5 references.—MR. 9424


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## 7.2 Valves, Pipes and Meters

7.2, 5.11

**Valves for Corrosive Fluids.** E. G. HOLMBERG. *Corrosion*, **11**, No. 9, 406t-414t (1955) Sept.

Methods are given whereby valves for control of corrosive fluids may be selected. Means of selecting suitable alloys are described, including laboratory and in-service tests, analogies of resistance through consideration of minor constituents and experience in actual plant service. Case histories of valve failures from corrosion are given and analyzed.

Detailed consideration is given to the design of valves and their component parts with recommendations concerning approved designs suitable for certain classes of service. The several kinds of flanged connections are described and their good and bad features analyzed. Details of internal construction that should be taken into account are itemized. Several valve standards are considered with respect to their applicability to corrosive services. The author reports it is the intention of the Manufacturers Standardization Society to develop standards for valves required to handle corrosive liquids at pressures over 150 psi. 9547

## 7.3 Pumps, Compressors, Propellers and Impellers

7.3, 1.6

**The Vertical Pump.** Book, 1954, 392 pp. Johnston Pump Co., 3272 E. Foothill Blvd., Pasadena 8, California.

This book provides a comprehensive study of vertical turbine, mixed flow and propeller pumps replete with tables, diagrams and illustrations (both pictorial and drawn). On the subject of corrosion it presents information on corrosion-resistant materials for pumps, recommended pump materials for corrosive liquids and general rules to be followed. The book is divided into five sections, each providing excellent coverage on the subjects of development of ground water resources; construction, design and performance characteristics of vertical turbine, mixed flow and propeller pumps; pump selection for hot, volatile, viscous and corrosive fluids; practical applications of vertical turbine, mixed flow and propeller pumps and engineering formulas and data. 9717

## 7.4 Heat Exchangers

7.4.1

**Corrosion Prevention in Cooling Water Heat Exchangers.** J. D. MUNRO. Standard Oil Company. *Petroleum Engineer*, **27**, C—35+11 pages (1955) Jan.

The heat exchanger is greatly responsible for the high degree of efficiency that exists in the petroleum refinery today. Because of the complexity of the heat exchanger, and conditions to which it is exposed, many problems arise. Corrosion caused by cooling water, especially sea water, has been one of the principal problems. This article is a contribution to the over-all effort to combat corrosion. Photographs, tables, diagrams, six references.—VISCO. 9403

7.4.1, 8.8.3, 8.8.5

**External (Heat) Exchangers Stem Chemical and Electrolytic Corrosion.** C. BUCK. *Iron Age*, **174**, No. 27, 50-51 (1954) Dec. 30.

Use of external heat exchangers to overcome chemical and electrolytic attack in heating or cooling of plating, anodizing or pickling solutions. A table gives recommended materials (e.g., steel, cast steel, cast high-nickel-chromium-iron alloy, stainless steel, tantalum, graphite and various plastics) for exchanger tubes, pumps, piping and fittings for commonly used plating, pickling and cleaning solutions.—BNF. 9759

## 7.5 Containers

7.5.5, 5.2.3

**Cathodic Protection of Storage Tanks.** B. D. ALLISON. *Diesel Power*, No. 2, 30-32 (1954) Feb.; *Ry. Track and Structures*, **50**, 54-56 (1954) Feb.

Details are given of the cathodic protection schemes, using graphite anodes and impressed current, which are being installed on all new fuel oil and water storage tanks erected by the Chicago and North Western Railway System.—ZDA. 9778

## 7.6 Unit Process Equipment

7.6.4, 3.2.2

**Localized Corrosion in Steam Boilers.** R. N. PARKINS. *Corrosion Technology*; **2**; Nos. 2, 3; 43-46, 79-81 (1955) Feb., Mar.

Corrosion which takes place in steam boilers is usually localized, leading to pitting or corrosion cracking rather than attack of a general nature. Oxygen pitting and pitting due to high salt concentrations are discussed. Oxygen pitting is associated with an incrustation of corrosion products over a region being attacked while other type of pitting leaves no corrosion products at point of attack, so that perforation of tube and shell walls may occur in a short time. Corrosion associated with high concentrations of caustic soda (caustic cracking), corrosion fatigue and deterioration due to local overheating are discussed. 22 references.—INCO. 9622

7.6.4, 3.5.11, 3.6.8

**Influence of Flow Rate on Scale Formation and the Subsequent Corrosion in Hot Water Supply Devices.** (In German). L. W. HAASE. *Werkstoffe u. Korrosion*, **6**, No. 2, 81-84 (1955) Feb.

Effects of water composition, container material and flow; benefits of depolarizer. Diagrams.—MR 9426

## 7.7 Electrical, Telephone and Radio

7.7.

**Automatic Clamp Designed to Terminate Aluminum Secondary Conductors at Poles.** F. T. HAUSLE. *Elec. World*, **142**, No. 26, 84-85 (1954) Dec. 7.

A dead-end clamp for terminating all-aluminum secondary conductors at poles is described. The clamp consists of one half of an all-aluminum "automatic" line splice coupled to an aluminum yoke, and a tin-plated copper-clad steel-wire loop detachable at one end of the yoke. The tinned loop is placed around a secondary spool insulator supporting either copper or aluminum conductors without possibility of electrolytic action. New and reused units were subjected to tension and vibration

tests before the connector was adopted as standard. Cost of this unit is slightly less than that of other methods, and installation labor is only one third. Three methods of pole termination are shown, viz. : aluminum secondary tapped to copper or aluminum through-line on same rack, aluminum-to-copper through-line connection made by shifting rack to field side of pole, and where strain insulators are installed as line breakers in the aluminum secondaries.—ALL. 9727

7.7, 5.4.5, 5.5.3

**Protective Coatings for Electrical Connections.** HOWARD B. GIBSON. *Product Eng.*, **26**, No. 4, 156-160 (1955) April.

The results of tests on 11 types of coating materials for copper or aluminum electrical connections are given. Specimens of thin, smooth, 1-in. bars of aluminum and copper were obtained in the following four categories: 1.) bars with contact surfaces not cleaned, 2.) bars with surfaces cleaned with abrasives, 3.) bars with contact surfaces chemically cleaned, 4.) bars with contact surfaces chemically cleaned and then covered with a protective coating. Electrical connections with contact pressures from 300 to 6000 lb./sq. in. were used. Measurements were taken at the beginning of the test, and after a six-month ageing period, in which the bars were exposed to outside industrial marine atmosphere. The results indicate that as the contact pressure is increased, the resistance decreases for both coated and unprotected contact surfaces, newly cleaned or aged six months. Resistance of the coated aluminum is less reversible than that of coated copper; but resistance of the unprotected aluminum returns to its original value, while that of copper remains at some value less than the original. In both cases the protective coating tends to maintain a reduced contact resistance, despite decreasing contact pressure. The effectiveness of hard and soft protective coatings is compared. Although the hard lacquer coatings have a higher final resistance, for most applications the lower resistance of the soft wax coating makes it most desirable to use.—ALL. 9373

## 7.10 Other

7.10, 6.4.2

**Aluminium Windows: Notes on Design and Manufacture.** Pamphlet, revised October, 1954, 33 pp. Published by Aluminium Labs. Ltd., Banbury.

Aluminum as window frame material; suitable alloys; assembly methods; finishing; installation and glazing; typical designs; and extruded sections.—BNF. 9761

## 8. INDUSTRIES

## 8.3 Group 3

8.3.6

**Conveying Equipment in Cane-Sugar Mills.** C. C. RINELLI, Chain Belt Co. Paper before Am. Soc. Mech. Engrs., Materials Handling Div. and Process Industries Div., Internat. Mtg., Mexico City, March 10-12, 1954. *Trans. ASME*, **77**, No. 4, 497-506; disc., 506-507 (1955) May.

Emphasis is placed on application of chains, sprockets, slats and other moving parts of main conveyors and elevators. Corrosion from juice, plus abrasion due to dirt and trash from cane, and load imposed by cane knives contribute to relatively short life expectancy of cane carriers. Cane-carrier chains are made of high-quality, heat-treated, precision-ground steels, and pins are made of heat-treated alloy steels. Juice-strainer, intermediate, cane-feeder, and bagasse-carrier chains are usually made of special-process alloy malleable iron. 3/16-in.-thick double beaded steel intermediate carrier slats should be adequate. Non-corrosive pins, washers and bushings should be used. Stainless steel pins and brass cotters give excellent service in some applications. Illustrations.—INCO. 9651

## 8.4 Group 4

8.4.3

**Good Engineering Pays Off in Slick-Wilcox Field.** W. H. ROSSER. Continental Oil Co. Paper before TPRC Mtg., College Station, Texas, 1955. *Oil Gas J.*, **54**, No. 7, 87-88 (1955) June 20.

Biggest operating problem in field to date has been corrosion, which is of the low-pressure sweet-oil-well type and becomes of serious nature when water production reaches 50 percent or more. High percentage of barium in produced waters further complicates problem. Greater portion of corrosion attack is of the pit type, thus indicating the major corrodent to be carbon dioxide. Degree of corrosion activity in individual wells is determined by use of steel coupons placed at various depths in the producing string. General method in use for corrosion protection is an inhibition program utilizing commercial organic inhibitors which are injected into casing annulus.—INCO. 9669

8.4.3, 1.7.1

**Current Status of Corrosion Mitigation Knowledge on Sweet Oil Wells.** A. Report of Technical Unit Committee T-1C on Sweet Oil Well Corrosion. H. E. GREENWELL, Chairman. *Corrosion*, **11**, No. 10, 61-63 (1955) Oct.

Unit Committee T-1C is interested in high pressure sweet oil well corrosion and its control and has accumulated considerable data on both water-independent and water-dependent wells. This report is a summary of the problems involved and a discussion of some theoretical aspects and practical mitigation measures.

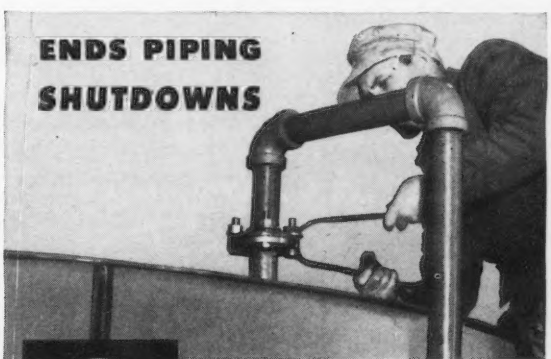
Corrosion in high pressure flowing oil wells is becoming increasingly common. Methods currently used to limit corrosion damage include coated tubing, inhibitors and alloy tubing, with tubing coated with baked on phenolics being favored most. Epoxies are being tested as a tubing coating.

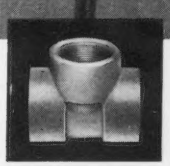
Lack of success with weighted inhibitor sticks is reported, but some operators are pushing sticks to bottoms with wire tools. Bottom hole injection is being tried by some, but because of gelling of diluents in wells with high bottom hole temperatures, caution in selecting diluents is advised. Results on use of alloy tubing are inconclusive.

Laboratory work on duplicating the conditions noted with respect to sparingly soluble sulfate scales has met with considerable success. A technique for preparing artificial scale is reported. A theory covering the reason for the porosity of the scale is advanced.

In connection with corrosion believed water dependent it is questioned whether circulation of a well after treatment down the annulus is beneficial. Some organic corrosion inhibitors are believed to accelerate corrosion at low concentrations.

A new task group organization has been made by the committee. 9757





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8.4.3, 3.2.2

**Deterrence of Hydrogen Blistering at a Fluid Catalytic Cracking Unit.** B. W. NEUMAIER AND C. M. SCHILLMOLLER. Paper before Am. Petroleum Inst., Div. of Refining, Midyear Mtg., St. Louis, May 9, 1955. *Oil Gas J.*, **54**, No. 3, 107-110 (1955) May 23.

Richfield Oil Corp. is preventing low-temperature hydrogen attack at its new Wilmington, California fluid unit. Most sulfides, and a large portion of other acidic compounds, are removed early in process stream. Diethanolamine absorption and extensive water washing are used. Caustic washing and feed dehydration are also employed. Facilities are available for adding polysulfide and inhibitor when they are needed. Unit is constructed of carbon steel throughout with a ⅛-in. corrosion allowance. Special retractable hydrogen-probe-test-coupon assembly was installed to evaluate corrosion rate and hydrogen-penetration rate. Diagrams, tables, 9 references.—INCO. 9613

8.4.3, 4.4.8

**Why M.E.A. Solution Breaks Down in Gas-Treating Service.** L. D. POLDERMAN, C. P. DILLON AND A. B. STEELE. *Oil Gas J.*, **54**, No. 2, 180-183 (1955) May 16.

Some gas-treating plants have serious corrosion problems resulting from breakdown of monoethanolamine into two degradation products, 1-(2-hydroxyethyl) imidazolidone-2 and N-(2-hydroxyethyl) ethylene diamine, which do not accept acid gases. Laboratory corrosion studies indicate that presence of monoethanolamine reduces vapor phase attack of carbon steel in water-carbon dioxide systems and that acid gases themselves are primary corrodents in uncontaminated solutions. Carbonated N-(2-hydroxyethyl) ethylene diamine at 0.5-5 percent concentrations contributes somewhat to liquid-phase amine corrosion. Qualitative corrosion tests on carbon-steel coupons immersed in various glycol-amine solutions and in aqueous M.E.A. solutions are shown. Degradation products can be removed by side stream distillation. Experimental data are tabulated. INCO. 9601

8.4.5

**Vapor Compression Evaporation Handles Radioactive Waste Disposal.** B. MANOWITZ, P. RICHARDS AND R. HORRIGAN. *Chem. Eng.*, **62**, No. 3, 194-196 (1955) Mar.

Vapor compression evaporation process for disposing of radioactive wastes is discussed. Great bulk of the waste to be concentrated is stored in three 100,000-gallon specially coated mild steel tanks. All remaining tanks, piping and concentration equipment are of stainless steel. The calandria, constructed of Type 316 ELC stainless steel, contains 894 tubes welded to tube sheets. Flowsheet and three references.—INCO. 9590

8.4.5, 6.2.2, 4.7

**Testing Heat Transfer and Corrosion of Globeiron for Fuel Cladding in a Sodium-Cooled Fast Breeder.** R. H. JONES (Hartford Electric Light Co., Conn.) AND R. E. LEE (Mine Safety Appliances Co., Callery, Penn.). *Nucleonics*, **13**, No. 2, 70-72 (1955) Feb.

Heat transfer and corrosion tests show that Globeiron, an iron alloy, is satisfactory as a thin-walled fuel-cladding material for 30-day exposures in a sodium-cooled fast reactor. The tests simulated reactor operation. The testing apparatus is described, and data and results are presented. Tests indicated that Globeiron maintained its original over-all heat-transfer coefficient throughout a 30-day period and that there was no fouling of the heat exchanger due to mass transfer in the sodium loop. Metallurgical examination showed no significant attack on the Globeiron specimen.—NSA. 9423

## 8.9 Group 9

8.9.2

**Corrosion in the Motor-Car. Part III. The Bodywork.** Z. S. MICHALEWICZ *Corrosion Technology*, **2**, No. 3, 75-78 (1955) Mar.

Finishes used on the bodywork of motorcars must provide adequate protection against corrosion under various climatic, atmospheric and operational conditions. Treatment of steel prior to painting, and the electroplated bright finishes, such as chromium-nickel, are described. Table lists some data obtained by Hudson and LaQue on the relative corrosivity of different atmospheres. Additional table gives results obtained with three steels, open-hearth iron, 0.2 percent copper steel and chromium-nickel-silicon-copper-phosphorus steel, exposed at Kure Beach, 80 ft. from the ocean. Results illustrated the superiority of low-alloy steels. 13 references.—INCO. 9597

8.9.3

**Here Is Why Pipe Lines Corrode.** MAURICE A. RIORDAN. *Pipe Line Industry*, **2**, 36-39 (1955) Mar.

Corrosion mechanisms; evaluation of corrosion circuits. Diagrams.—BTR. 9652

8.9.3, 1.7.3

**Organization and Activity of the Corrosion Control Group of a Large Public Utility.** JAMES W. MCAMIS. *Corrosion*, **11**, No. 8, 330t-334t (1955) Aug.

Methods developed to accumulate information and direct the corrosion control activities of a utility with 2900 miles of piping with 335,000 meters on service take-offs are discussed. Data are collected in the form of maps, recommendations and drawings of installations. Available information on relative corrosivity of certain areas is plotted to a central map. The Corrosion Control Group generally supervises mitigation measures, with actual work under foremen, who also are responsible for training personnel. Testing of the effectiveness of installations has been limited by lack of time and personnel, but more is expected to be done soon. Use of holiday detectors is recommended. 9553

8.9.3, 5.2.1

**Coatings and Cathodic Protection for Steel Pipelines.** G. I. RUSSELL. *Corrosion Prevention & Control*, **2**, Nos. 4, 5; 21-24 (1955) April, May.

Introduction of electrical protection has resulted in a realignment of ideas concerning subsurface corrosion prevention for pipelines. Protective value is no longer a function of its thickness, or its inhibitive or shielding effects, but it is a function of its electrical resistance also, i.e., the lower the conductance the lower the amount of current required for protection and the lower the cost for installing and maintaining the cathodic system. Pipeline corrosion specialists on the whole still believe that the joint use of cathodic protection and high quality coating combination will continue to provide the best performance at minimum projected total cost. 7 references.—INCO. 9665

8.9.5

**Corrosion of Ships.** A. PICKWORTH. *Corrosion Technology*, **2**, No. 2, 32-36 (1955) Feb.

Preservation of inner and outer surfaces of steel ships is covered. Effect of design, effect of surface water, inspection for corrosion, removal of mill scale, preparation for painting and choice of paints are discussed. Use of red lead to protect the outside of the hull and use of aluminum paint on internal surfaces are considered.—INCO. 9584

8.9.5, 1.2.2, 5.8.2, 5.2.1

**Countermeasures for Control of Internal Corrosion of a Tanker Ship.** CHARLES P. DILLON. *Corrosion*, **11**, No. 9, 393t-405t (1955) Sept.

Internal corrosion in wing tanks of a tanker ship, the SS R. E. Wilson, is estimated to cost $125,000 annually. Corrosion mechanisms are described in terms peculiar to the operation of this ship. Various counter measures are considered, including coatings, inhibition of cargo and ballast, use of inhibited fresh and sea water, changes in Butterworthing schedule, cathodic protection with and without concurrent inhibition. Both laboratory and in-service tests are reported for numerous mitigation methods. It has been established tentatively that the best solution for this ship is concurrent inhibition of cargo with an oil-soluble inhibitor and treatment of empty tanks with soluble-oil inhibited salt water wash. Reduction of corrosion up to 75 percent is expected with a net annual saving on the order of $65,000. 9549

8.9.5, 6.4.2, 1.2.2

**Conversion of Costing for a Ship from a Steel to an Aluminium Basis.** (In German.) E. HELZENGREEN. *Schiff u. Hafen*, **1954**, 432-436; abridged: *Aluminium*, **30**, No. 11, 472-473 (1954) Nov.

Financial estimate for using aluminum instead of steel. The steel vessel taken as example weighs 2263 tons, and assuming identical dimensions, capacity and strength requirements the aluminum vessel would weigh 1775 tons. The lower operating cost would offset the higher production cost in 11½ years.—BNF. 9738

## 8.10 Group 10

8.10.2, 7.6.3, 7.4.1

**Use of Autoclaves and Flash Heat Exchangers at Beaverlodge.** R. W. MANCANTELLI AND J. R. WOODWARD. *Mining Eng.* (Trans. AIME), **7**, No. 6, 557-561 (1955) June.

Describes process of extraction and precipitation of uranium ore at Beaverlodge property of Eldorado Mining & Refining Ltd. Autoclaves are used for leaching instead of conventional agitators, and flash heat exchangers have been substituted for normal tubular ones. Severe pitting on steel at liquid line is associated with pulp splash. Action is caused by differential aeration—oxide film on steel is not repaired by oxygen from air because of limited supply available under a pulp splash. Most severe pitting is that associated with sulfide-rich froth, containing sulfides, graphite, and ferric and cupric ions, that floats on surface of ore stream and clings at certain areas to walls of autoclave. Battelle Mem. Inst. is studying this corrosion problem.—INCO. 9599

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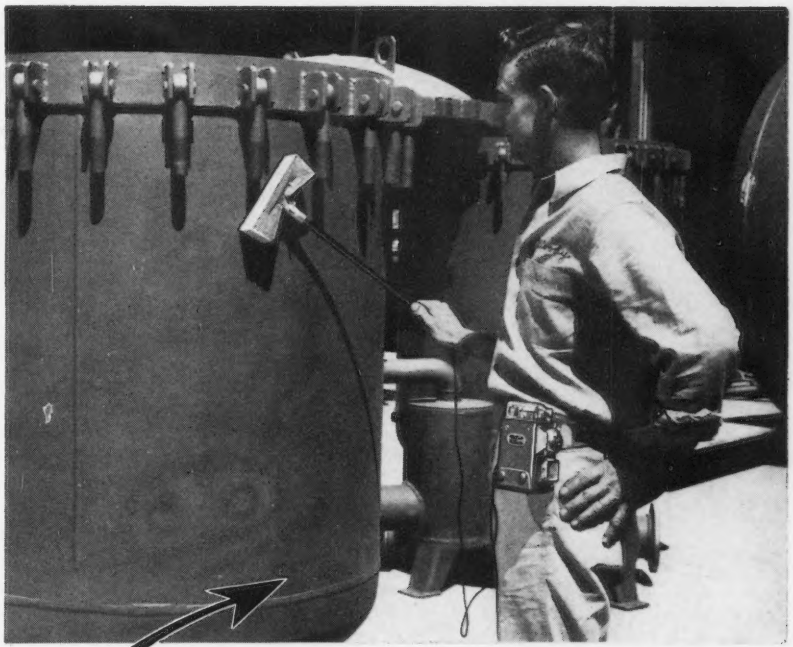

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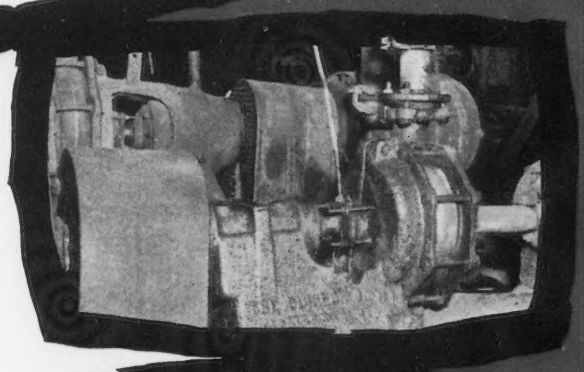

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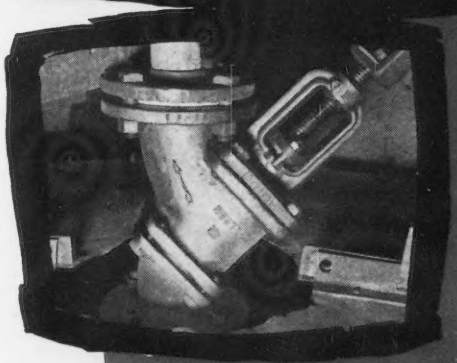

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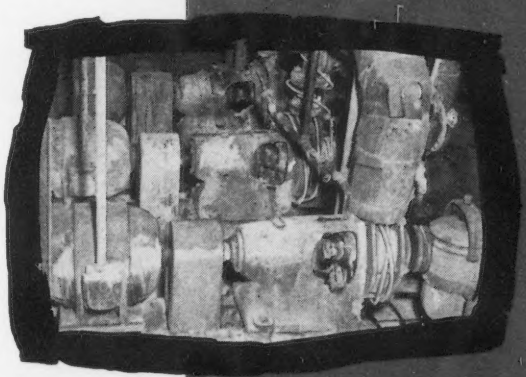

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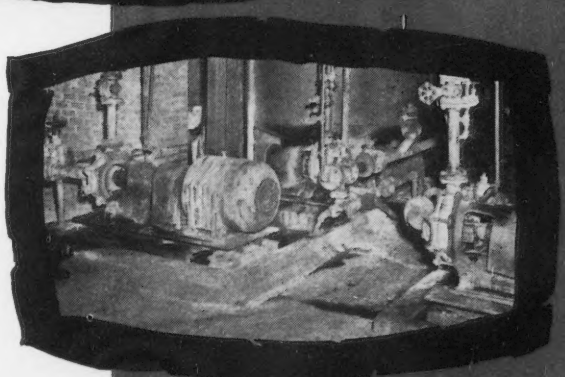

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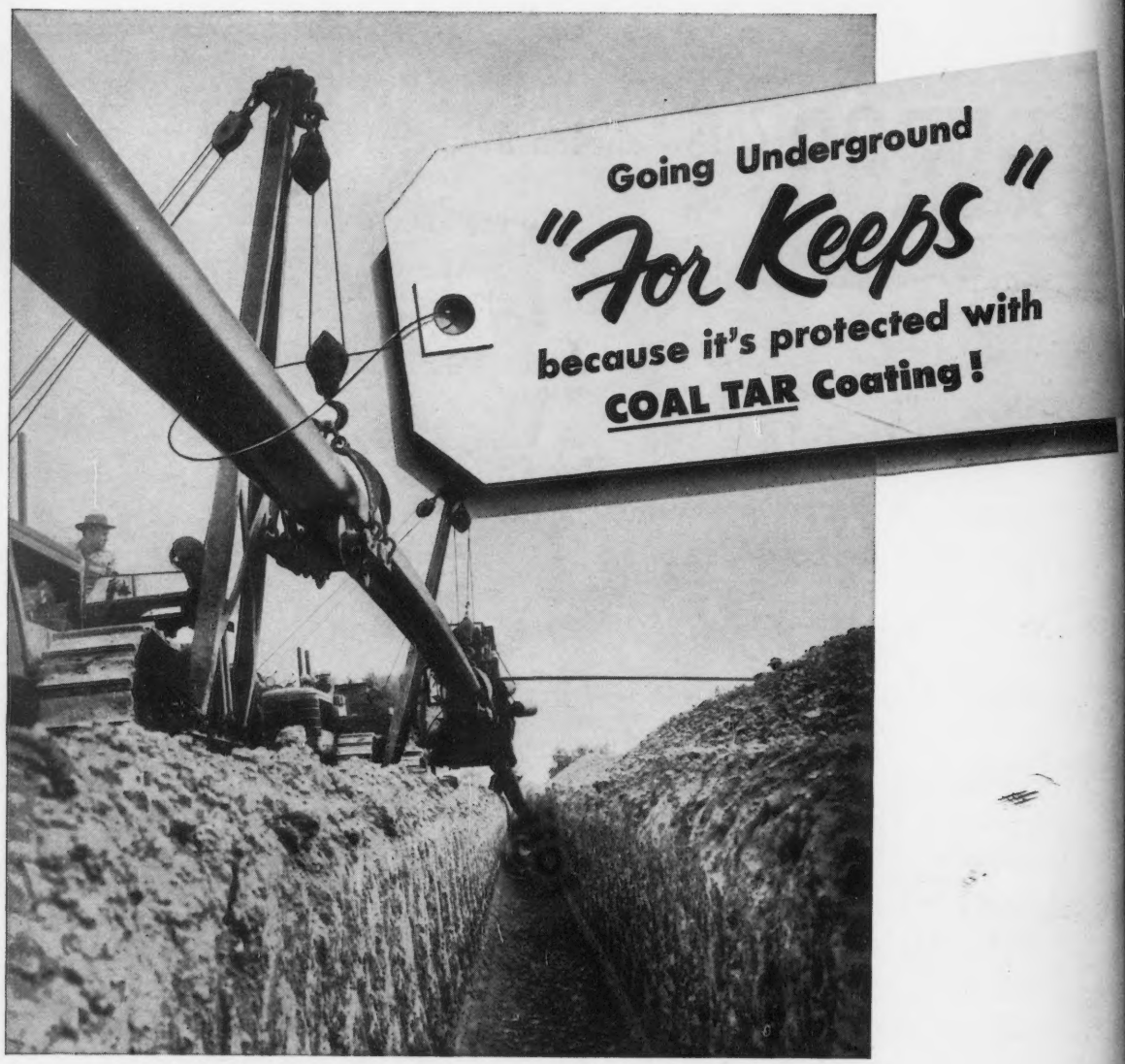


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